January 14, 2025

Submitted via ca.gov

Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Tier 2 Pathway Application No. B0695

Dear Chair Randolph,

Leadership Counsel for Justice & Accountability, Central Valley Defenders of Clean Water & Air, Animal Legal Defense Fund, and Food & Water Watch (collectively, "Commenters") write in opposition to FirstElement Fuel's Tier 2 pathway application. As Commenters have explained through numerous comments, the Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program (included and incorporated here as Exhibit A), and the Petition for Reconsideration (included and incorporated here as Exhibit B), the California Air Resources Board's ("CARB") treatment of factory farm gas under the Low Carbon Fuel Standard ("LCFS") is flawed, and staff's assessment of this application is no different. CARB cannot certify this application.—especially now that it has directed the Executive Officer in Resolution 24-14 to "prepare a plan for initiating, developing, proposing, and implementing a livestock methane regulation[.]"[1]

Commenters oppose this application because three of the four proposed pathways have incorporated—by book and claim accounting—the flaws that infect all pathway applications for fuels derived from factory farm gas. First, the application incorporates an unlawfully truncated system boundary that ignores upstream emissions from feedstock production at the source factory farms—Lakeshore Dairy, Lamb Farm, and Boxler Dairy in New York, which, as of 2022, confined a total of 8,400 cows—and downstream emissions such as those from storage and disposal of digestate, resulting in artificially low Carbon Intensity (CI) values and inflated credit generation. A fuel pathway life cycle analysis must take into account "feedstock production" and "waste generation, treatment and disposal."[2] In addition to the evidence provided in Exhibits A and B, more recent research indicates that emissions from factory farm gas production are significantly higher than currently appreciated, with especially high emissions from digestate storage and methane releases from digesters.[3] The digestate study did not consider additional emissions from digestate handling and application, which is another potentially large source of emissions resulting

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[1] CARB, PUBLIC HEARING TO CONSIDER PROPOSED LOW CARBON FUEL STANDARD AMENDMENTS, RESOLUTION 24-14 at 7 (Nov. 8, 2024), https://perma.cc/V4UV-YFW6.
[2] Cal. Code Regs. Tit. 17 §§ 95481(a)(66), 95488.7(a)(2)(B).
[3] Semra Bakkaloglu et al., *Methane Emissions Along Biomethane and Biogas Supply Chains Are Underestimated*, 5 ONE EARTH 724–736 (June 17, 2022), https://www.sciencedirect.com/science/article/pii/S2590332222002676; FOOD & WATER WATCH, THE PROOF IS IN THE PLUMING: FACTORY FARM BIOGAS HAS NO PLACE IN THE LOW CARBON FUEL STANDARD (Feb. 2024), https://perma.cc/MN7Q-HNEV.

from factory farm gas production that must be included in the pathway life cycle analysis.[4] Yet CARB and the pathway applicant ignore these and other emissions. In other words, this application dramatically undercounts the greenhouse gas emissions associated with this fuel by failing to apply the required "well-to-wheel" analysis.

Concurrently, this application overcounts environmental benefits by ignoring that this is, in one factory farm owner's words, "***lucrative***" feedstock production.[5] Liquified manure rotting anaerobically in massive waste "lagoons" is not an unavoidable and natural consequence of animal agriculture operations. Manure lagoons are the result of the factory farms' intentional management choices to maximize profits—and now methane emissions—while externalizing pollution costs. CARB cannot ignore that the emissions the pathway applicant claims as captured from these factory farms' lagoons are intentionally created in the first place.[6] The manure handling practices at these facilities are integrated parts of generating and using factory farm gas. Thus, the gas generated at these facilities is an intentionally produced product and cannot be claimed as "captured" or "avoided" to secure a lucrative negative CI value.

Second, CARB has failed to ensure that the additionality requirements of Health and Safety Code section 38562 are met.[7] If CARB had done so, it would have concluded that the methane capture at issue is patently not additional. The Lakeshore, Lamb, and Boxler digesters, which are also the digesters for pathway applications B0345, B0346, and B0347,[8] have existed since 2017, 2008, and 2010, respectively, without taking advantage of the LCFS.[9] Further, the Lakeshore and Boxler digesters have participated in the federal RFS program.[10] Accordingly, any purported emission reductions associated with these digesters have been occurring for years and presumably will continue to occur with or without LCFS subsidization. Stated differently, these are purported

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[4] *Id.* at 728; Michael A. Holly et al., *Greenhouse Gas and Ammonia Emissions from Digested and Separated Dairy Manure During Storage and After Land Application*, 239 AGRIC. ECOSYSTEMS & ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007; Roger Nkoa, *Agricultural benefits and environmental risks of soil fertilization with anaerobic digestates: a review*, 34 AGRONOMY FOR SUST. DEV. 473 (2014), https://link.springer.com/article/10.1007/s13593-013-0196-z; F. Montes et al., *SPECIAL TOPICS — Mitigation of methane and nitrous oxide emissions from animal operations: II. A review of manure management mitigation options*, 91 J. OF ANIMAL SCI. 5070 (2013), https://academic.oup.com/jas/article/91/11/5070/4731316; Kurt Möller & Walter Stinner, *Effects of different manuring systems with and without biogas digestion on soil mineral nitrogen content and on gaseous nitrogen losses (ammonia, nitrous oxides)*, EUROPEAN J. OF AGRONOMY (2009), https://www.sciencedirect.com/science/article/abs/pii/S1161030108000695?via%3Dihub.

[5] Stacey Smart, *Deer Run Dairy wins national sustainability award*, DAIRY STAR (June 27, 2022), https://dairystar.com/Content/Home/Home/Article/Deer-Run-Dairy-wins-national-sustainability-award/80/254/18626 (emphasis added) ("Installed in 2011, the digester supplied power to nearly 600 homes. In 2020, the farm converted over to renewable natural gas that is injected into the pipeline, which Duane said is a more lucrative option.").

[6] *See* Emily Grubert, *At Scale, renewable natural gas systems could be climate intensive: the influence of methane feedstock and leakage rates*, 15 ENVTL. RES. LETTERS (Aug. 2020) ("This analysis shows that 1) RNG from intentionally produced methane, even from climate-neutral CO2 sources, has substantial climate impacts at methane leakage levels observed in the existing, mature biogas industry; (2) for any meaningful system scale, RNG is likely to be derived from intentionally produced methane; and (3) even RNG from waste methane can have negative climate impacts relative to the most likely alternative of flaring, not venting, the methane when leakage from RNG production and use exceeds flaring loss rates." (internal citations omitted)).

[7] *See* Ex. A, Petition for Rulemaking, section III.A.2; Ex. B, Petition for Reconsideration, section III.A.3.

[8] Application B0695 CARB Staff Summary at 1–2.

[9] Application B0345 CARB Staff Summary at 1; Application B0346 CARB Staff Summary at 1; Application B0347 CARB Staff Summary at 1.

[10] Application B0345 CARB Staff Summary at 1; Application B0347 CARB Staff Summary at 1.

emission reductions that "otherwise would occur."[11] Thus, certification of this pathway with this proposed CI value would openly violate section 38562 by crediting nonadditional reductions.

Third, this application is a good example of how CARB's flawed approach is rewarding the biggest factory farm polluters and incentivizing further expansion and herd consolidation, which does more climate harm than good. The factory farms that would produce the feedstock and the resulting factory farm gas involved in this project are not sustainable family farms—they are large industrial operations that confine thousands of cows. As Commenters explained in comments on applications B0345, B0346, and B0347, Lakeshore Dairy confines 2,500 cows, Lamb Farm confines 2,700 cows, and Boxler Dairy confines 3,200 cows—a total of 8,400 cows.[12] CARB should not allow these factory farms—or the applicant—to profit from the LCFS.

Fourth, applications B0345, B0346, and B0347 are so opaque that it is impossible for Commenters or other stakeholders to meaningfully evaluate them, as the life cycle analyses redact information critical to understanding CI calculations.[13] Thus, it is also impossible for Commenters or other stakeholders to meaningfully evaluate this application.

Finally, the CI values work an additional environmental injustice on Californians who will be exposed to higher levels of pollution from fossil transportation fuel and dirty vehicles made possible by excessive credit generation at factory farms. CARB has acknowledged that pollution from transportation fuels has racially disparate impacts. CARB's ongoing certification of fuel pathways with extreme negative CI values allows more pollution from deficit holders to perpetuate and exacerbate this injustice.[14]

As this application highlights, CARB's unlawful and unjust administration of the LCFS program is also causing environmental and public health harms not just in California, but to communities and ecosystems across the United States—in this case New York—by incentivizing and rewarding some of the worst factory farm practices by making them more "***lucrative***." If California is serious about being a climate and environmental leader, the state should not be catalyzing the continuation and expansion of such polluting industries.

Commenters request that CARB deny the application. To do otherwise will violate California law, further destroy the integrity of the LCFS market, undermine the state's climate change mitigation efforts, and harm communities in California and across the country.

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[11] Health & Saf. Code, § 38562, subd. (d)(2).

[12] Application B0345 CARB Staff Summary at 1; Application B0346 CARB Staff Summary at 1; Application B0347 CARB Staff Summary at 1.

[13] Publicly posted application materials "must provide sufficient information to allow for meaningful stakeholder review." CAL. AIR RES. BD., LOW CARBON FUEL STANDARD (LCFS) GUIDANCE 20-051 (Apr. 2020), https://perma.cc/856Y-CVVZ; *see also* SB 32, 2016 Cal. Legis. Serv. Ch. 249 § 1(d) (stating that CARB "shall achieve the state's more stringent greenhouse gas emission reductions *in a manner that* benefits the state's most disadvantaged communities and *is transparent and accountable to the public* and the Legislature) (emphasis added).

[14] *See* 2020 Mobile Source Strategy at 26–27, https://ww2.arb.ca.gov/sites/default/files/2021-12/2020_Mobile_Source_Strategy.pdf.

Respectfully,

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Exhibit A: Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program

BEFORE THE CALIFORNIA AIR RESOURCES BOARD

PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM

PETITION FOR RULEMAKING

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I. INTRODUCTION

The California Air Resources Board (CARB) allows inflated and non-additional credits derived from factory farm gas[1] to undermine the integrity of the Low Carbon Fuel Standard (LCFS) pollution trading scheme and exacerbate discriminatory environmental and public health harms in the San Joaquin Valley. The LCFS increases harmful pollution to air, water, and land in rural low-income and Latina/o/e communities; inflates factory farm gas reductions by excluding upstream and downstream emissions; allows non-additional reductions from other factory farm gas incentive programs to generate credits; fails to achieve reductions from transportation fuels when these inflated and non-additional factory farm credits justify excessive fossil fuel emissions; and perversely incentivizes increased greenhouse gas emissions and pollution from dairy and pig factory farms.

To remedy these deficiencies, the Association of Irritated Residents (AIR), Leadership Counsel for Justice & Accountability, Food & Water Watch, and Animal Legal Defense Fund petition the CARB for rulemaking to amend the LCFS to exclude all fuels derived from factory farm gas. In the alternative, CARB must reform the LCFS program to account for the full life cycle of factory farm gas emissions – including all upstream and downstream emissions from activities and inputs at dairy and pig facilities – and exclude non-additional emissions reductions that occur as a result of other factory farm gas incentives, including the Dairy Digester Research Development Program. CARB must also take steps to ensure that its policies and practices do not impose discriminatory harms on low-income and Latina/o/e communities in the San Joaquin Valley.

In 2006, the California Legislature determined that climate change posed "a serious threat to the economic well-being, public health, natural resources, and the environment of California."[2] To address these threats, CARB designed a range of programs that would monitor, regulate, and ultimately reduce greenhouse gas emissions, including the LCFS.[3] But as written and as implemented, the LCFS pathways for factory farm gas do not effectively reduce greenhouse gas emissions, violating CARB's obligation to achieve the maximum cost-effective and technologically feasible emissions reductions.

The LCFS intentionally promotes factory farm gas, a fusion of Big Ag and Big Oil & Gas, two of the industries most responsible for the climate crisis and whose entire business model relies on extraction and exploitation. Big Ag brought us polluted wells, foul air, antibiotic-resistant pathogens, methane-spewing manure lagoons, and workplace conditions that caused rampant outbreaks of COVID-19. Big Ag has driven family farmers off their farms, stripped wealth from our communities, and gutted our rural main streets. Big Oil & Gas brought us countless oil spills, tanker wrecks, pipeline explosions, and climate damage. There is no reason to entrust our future to the very industries responsible for the harms the LCFS seeks to address.

[1] Factory farm gas refers to the fuel the LCFS designates "biomethane from the anaerobic digestion of dairy and swine manure."
[2] CAL. HEALTH & SAFETY CODE § 38501.
[3] CAL. HEALTH & SAFETY CODE § 38510.

The results of CARB's embrace of these false solutions to the benefit of Big Ag and Big Oil & Gas are clear: due to the LCFS's deficient accounting of the emissions from factory farm gas, the program encourages increased production of the liquified manure necessary to generate factory farm gas, resulting in *more* intentionally created methane from new and expanding dairy and pig facilities. By propping up factory farm gas, the LCFS provides a new way for big corporations to get rich off a problem they created. In CARB's accounting of the carbon intensity of factory farm gas, the LCFS fails to include the full quantity of associated upstream and downstream greenhouse gas emissions, leading to an exaggerated negative carbon intensity value and a corresponding inflation of LCFS credit prices for factory farm gas. The resulting inflated credits do not encourage emissions reductions, instead, they reward factory farms for the production of toxic manure as though it were a cash crop. This "hot air" in the credit market, along with the award of credits for reductions from other incentive programs that would have occurred anyway, undermines the LCFS framework by allowing transportation fuel producers to emit more climate pollution based on illusory reductions.

No amount of corporate public relations spin, greenwashing, or deficient carbon intensity calculations can hide the fact that factory farm gas is created from massive harm. By incentivizing increased manure production and liquification, the LCFS program also fails to maximize additional environmental benefits in violation of the *Global Warming Solutions Act of 2006* (AB 32), and even increases the well-documented environmental and public health harms caused by pig and dairy factory farms. These facilities release enormous quantities of solid, liquid, and gaseous waste. In addition to greenhouse gas emissions, the waste from both pigs and dairy cows releases various co-pollutants including ammonia, hydrogen sulfide, volatile organic compounds (VOCs), and severe odor. The factory farm system relies on disposing the manure nitrogen on crops, which also leads to both nitrous oxide emissions and nitrate contamination of groundwater. Experience tells us that racism, exploitation, and extraction are embedded in the factory farm system – we know these harms are disproportionately imposed on Black, Indigenous, People of Color, and low-income communities around the country. In California, these harms discriminatorily impact low-income and Latina/o/e communities in the San Joaquin Valley in violation of state and federal law.[4]

CARB has an affirmative duty under Government Code section 11135 (CA 11135) and Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d, to ensure that its policies and practices do not have a discriminatory impact on the basis of race.[5] CARB has an affirmative duty under AB 32 to ensure that "activities undertaken to comply with the regulations do not disproportionately impact low-income communities" and to design regulations in a manner that is equitable.[6] Finally, Government Code section 12955 (CA 12955) prohibits any practice or program that has a discriminatory effect on members of protected classes with respect to housing opportunities, including with respect to the use and enjoyment of dwellings.[7] Furthermore, the

[4] Addressing discriminatory impacts resulting from the LCFS's inclusion of factory farm gas in other parts of the country where dairy and pig factory farms are concentrated is beyond the scope of this petition. However, CARB should also evaluate these potential impacts, given that the program includes applicants from around the country. CAL. AIR RES. BD., *LCFS Pathways Requiring Public Comments*, https://ww2.arb.ca.gov/resources/documents/lcfs-pathways-requiring-public-comments#t2.

[5] CAL. GOV'T CODE § 11135; 42 U.S.C. § 2000d.

[6] CAL. HEALTH & SAFETY CODE § 38562(b).

[7] CAL. GOV'T CODE § 12955.8; CAL. CODE REGS. TIT. 2 § 12161.

accountability our democracy depends on the public knowing the truth: who is benefiting, where the money is coming from, who is defining the problem, who is being impacted, and how they are harmed by the LCFS. By failing to even conduct a transparent disparity analysis of this highly-technical program, CARB impedes the public's ability to fairly evaluate CARB's choice to prop up Big Ag and Big Oil & Gas.

A people's government – our government – protects and serves the people's interests. It invests in food and climate solutions that create a healthy future for our children and grandchildren. It invests in good jobs that strengthen our rural communities. But CARB has created and implemented a pollution trading scheme that benefits polluters rather than uses the power granted by the people of California to prevent harms. On top of decades of discriminatory impacts in the San Joaquin Valley, California is facing the dire impacts of the climate crisis. We cannot afford a scheme that serves corporate interests over the people's needs.

To remedy these harms and to bring the LCFS regulation into compliance with state and federal law, the petitioners request that CARB amend section 95488.9 of the LCFS to exclude any "fuel pathway that utilizes biomethane from dairy and swine manure digestion."[8] In the alternative, petitioners request that CARB amend the LCFS regulation to (a) ensure that the life cycle analysis for biomethane from dairy and swine manure is expanded to include a full accounting of life cycle emissions; (b) amend section 95488.9 to ensure additionality of reductions; (c) properly classify methane from swine and dairy factory farms as intentionally occurring; (d) ensure compliance with state and federal civil rights law, including but not limited to conducting disparity analyses of LCFS pathways and credit trading; and (e) ensure the LCFS provides environmental benefits and does not degrade water quality and interfere with efforts to improve air quality in the San Joaquin Valley.

II. BACKGROUND

A. THE LCFS PROGRAM

AB 32 set a statewide target to reduce California's greenhouse gas emissions to 1990 levels by 2020.[9] In 2007, Governor Arnold Schwarzenegger issued Executive Order S-01-07, which directed CARB to adopt the LCFS pollution trading scheme to diversify California's transportation fuels and curb dependence on petroleum.[10] The California Office of Administrative Law approved the LCFS regulation in 2010 and the regulation has since undergone four rounds of amendments.[11]

According to CARB, "[T]he LCFS is designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce

[8] CAL. CODE REGS. TIT. 17 § 95488.9.
[9] CAL. HEALTH & SAFETY CODE § 38550.
[10] CAL. EXEC. DEP'T, Exec. Order No. S-01-07, (Jan. 22, 2007), *available at* https://www.library.ca.gov/Content/pdf/GovernmentPublications/executive-order-proclamation/5107-5108.pdf; *see also generally,* CAL. HEALTH & SAFETY CODE § 38560.5 (requiring CARB to establish GHG reduction measures).
[11] CAL. CODE REGS. TIT. 17 § 95480 et seq.

greenhouse gas emissions and decrease petroleum dependence in the transportation sector."[12] The LCFS, like similar pollution trading schemes, constructs a market where credits and deficits that represent emissions in relation to a declining baseline can be traded. These tradeable LCFS credits provide a new revenue stream for producers of fuels that have been deemed low-carbon intensity with the goal of incentivizing increased production and displacing the use of more greenhouse gas-intensive fuels. The LCFS requires entities that produce conventional transportation fuels to report the carbon intensity of these fuels, while certain alternative fuel producers may opt into the program and demonstrate their fuel's carbon intensity in their application.[13]

Every year, CARB sets progressively lower benchmarks for the carbon intensity of fuels.[14] Transportation fuels with carbon intensity values above the annual benchmark generate deficits, and transportation fuels with carbon intensity values below the benchmark generate credits (see Figure 1, Appendix C).[15] While obligated parties are required to either meet the benchmark or purchase credits to offset the extra emissions associated with their fuel, voluntary parties that produce alternative, low-CI fuels are incentivized to participate because fuels with carbon intensities below the benchmark generate revenue through the sale of LCFS credits.[16]

The LCFS regulation defines "carbon intensity" as "the quantity of life cycle greenhouse gas emissions, per unit of fuel energy, expressed in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ)."[17] The emissions included in each fuel's carbon intensity calculation are usually bounded by "fuel pathways," defined as "the collective set of processes, operations, parameters, conditions, locations, and technologies throughout all stages that CARB considers appropriate to account for in the system boundary of a complete well-to-wheel analysis of [a given] fuel's life cycle greenhouse gas emissions."[18] Accurate and thorough life cycle analyses for each fuel and the accurate accounting of the baseline against which each fuel's carbon intensity is compared are independent and necessary preconditions for the program to identify which fuels to encourage to decrease net greenhouse gas emissions.

The LCFS classifies fuel pathways into three groups: Lookup Table, Tier 1, and Tier 2 pathways.[19] Regulated parties can register their fuels using the standard pathways in the Lookup

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[12] *Low Carbon Fuel Standard: About,* CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Oct. 12, 2021).
[13] CAL. CODE REGS. TIT. 17 §§ 95483-95483.1.
[14] CAL. CODE REGS. TIT. 17 § 95484.
[15] *Id.*
[16] CARB accounts for credits and implements credit transfers with the LCFS Reporting Tool and Credit Bank & Transfer System. CAL. AIR RES. BD., *LCFS Registration and Reporting*, https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-registration-and-reporting (last visited Oct. 12, 2021).
[17] CAL. CODE REGS. TIT. 17 § 95481(a)(26). "Life Cycle Greenhouse Gas Emissions," in turn, is defined as "the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions, such as significant emissions from land use changes) as determined by the Executive Officer, related to the full fuel life cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential. CAL. CODE REGS. TIT. 17 § 95481(a)(88).
[18] CAL. CODE REGS. TIT. 17 § 95481(a)(66).
[19] CAL. CODE REGS. TIT. 17 § 95488.1(a).

Table if the fuel produced "closely corresponds" to a Lookup Table pathway.[20] Tier 1 and Tier 2 pathways are open to voluntary applicants, including those seeking credit for factory farm gas. Tier 1 is for "the most common low carbon fuels" and uses a Simplified CI calculator, where Tier 2 is for "innovative, next generation fuel pathways," and uses the full CA-GREET3.0 model.[21] Tier 1 includes fuels like ethanol and biomethane anaerobic digesters of dairy and swine manure, among others.[22] Tier 2 includes fuels from sources not in Tier 1 as well as pathways included in Tier 1 that use "innovative production methods."[23] The majority of factory farm gas producers apply for Tier 2 pathways rather than the Tier 1 pathway.

Ten years after enacting AB 32, the California Legislature set a new target for greenhouse gas emissions in Senate Bill 32 (SB 32) – 40 percent below 1990 levels.[24] The Legislature stipulated, however, that SB 32 would only be operative if it also enacted Assembly Bill 197 (AB 197), which amended AB 32 in several ways.[25] AB 197 added Section 38562.5, which required that regulations promulgated to achieve emissions reductions beyond the statewide greenhouse gas limit, including the LCFS, consider the social costs of greenhouse gases, prioritize direct emissions reductions, and incorporate the requirements of Section 38562(b).[26] These requirements include crucial mandates to design the regulations in a manner that is equitable; ensure that activities taken to comply with the regulations "do not disproportionately impact low-income communities" and "do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions;" and consider the overall societal benefits, including reductions in other air pollutants and other benefits to the environment.[27]

B. THE SAN JOAQUIN VALLEY

California's San Joaquin Valley, as discussed in this petition, refers to eight counties that compose the valley floor from San Joaquin County in the north, to Kern County in the south. While disadvantaged communities within the region confront air pollution, toxic emissions, and unsafe drinking water at rates and degrees disproportionate to other communities in the state, the San Joaquin Valley is also home to resilient, diverse communities and networks that have worked together over decades to promote robust mutual aid networks, expand civic engagement, and lead

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[20] CAL. CODE REGS. TIT. 17 § 95488.5(a)(1)-(6) ("Closely corresponds" means that the applicant's fuel pathway and a pathway on the Lookup Table are consistent in feedstock, production technology, the region in which the feedstock and fuel is produced, transport distance (if applicable), types and amount of thermal and electrical energy used in feedstock and finished fuel production, and that the CI of the entity's product is lower than or equal to the CI of the pathway in the lookup table.)

[21] CAL. AIR RES. BD., LCFS Guidance 19-01, Book and Claim Accounting for Low-CI Electricity 2, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-01.pdf. While Tier 1 applicants provide a "discrete set of inputs" based on the specifics of their operations to be used by one of the pre-existing Tier 1 Simplified CI Calculators, Tier 2 applicants must conduct and submit a full life cycle analysis using the CA-GREET3.0 model for their own customized pathway. CAL. CODE REGS. TIT. 17 § 95488.3.

[22] CAL. CODE REGS. TIT. 17 § 95488.1(c).

[23] CAL. CODE REGS. TIT. 17 § 95488.1(d).

[24] CAL. HEALTH & SAFETY CODE § 38566.

[25] SB 32, 2016 CAL. LEGIS. SERV. CH. 249.

[26] AB 197, 2016 CAL. LEGIS. SERV. CH. 250.

[27] CAL. HEALTH & SAFETY CODE §§ 38562(2), (4), (6).

efforts from the household to the community level to model climate resilience and environmental stewardship.

The region is known for and, to a great extent, characterized by industrial agricultural operations, including large confined animal feeding operations. Decades of similar investment, land use, and economic development strategies have failed and continue to fail to prioritize the economic well-being and health of San Joaquin Valley residents, leading to severe income inequality, poverty, and environmental degradation despite the inherent assets of the region.

The "disadvantaged communities" of California, as defined pursuant to Senate Bill 535, are concentrated in the San Joaquin Valley.[28] Seven of the eight counties in the Valley (all except San Joaquin County) report mean income well below the 120% limit that defines low-income.[29] Every county in the San Joaquin Valley has lower household and per capita incomes, and higher poverty rates than California as a whole.[30] While median household income in California in 2019 was $75,235, countywide household median incomes for San Joaquin Valley Counties ranged from $49,687 to $64,432. The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $53,672 and $49.687 – both at 71 percent or below statewide median income.[31] Notably, nine of ten of the most recent applications for consideration for Low Carbon Fuel Standard Tier 2 Pathways from California factory farm gas were in Tulare County and Kern County. Kern County, like Merced and Tulare, faces disproportionately high poverty rates at 19 percent. Even this data likely inflates reported income level, because it may exclude the San Joaquin Valley's thousands of undocumented residents and residents of the Valley's unincorporated communities.[32]

San Joaquin Valley residents are disproportionately Latina/o/e as compared to California as a whole. All eight San Joaquin Valley Counties have higher Latino populations than the state,[33] with populations ranging from 42 percent to 65.6 percent, as compared to the state population with

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[28] CAL. ENV'T PROT. AGENCY, *Designation of Disadvantaged Communities Pursuant to Senate Bill 535 (De León)* 1-32 (Apr. 2017), https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf.

[29] Section 39711 of the Health and Safety Code sets the ceiling for low-income communities at 120% of the area median income. Additionally, Section 39711 designates communities with disproportionate environmental impacts and concentrations of low income, high unemployment, low educational attainment, and other burdensome socioeconomic factors as disadvantaged communities. All eight counties of the San Joaquin Valley fall within these categories. *See Maps & Data,* CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Apr. 9, 2021) (flagging areas of California that exhibit high to low pollution burdening scores). *Income Limits*, U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il.html#2020_data (last updated Apr. 1, 2020) (choose 30% Income Limit for ALL Areas (Excel)); *FY 2020 State Income Limits* (2020), U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il/il20/State-Incomelimits-Report-FY20r.pdf.

[30] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[31] Poverty rates in every single county in the San Joaquin Valley also exceed poverty rates in California, with Merced, Tulare facing 17 and 18.9 percent poverty rates (as compared to 11.8 percent at the statewide level). *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[32] 310,000 people live in low-income unincorporated communities in the San Joaquin Valley – "this is 70,000 more than what the Census Bureau included in its low-income Census Designated Places in the San Joaquin Valley." POLICYLINK, *California Unincorporated: Mapping Disadvantaged Communities in the San Joaquin Valley* 9 (2013), https://www.policylink.org/sites/default/files/CA%20UNINCORPORATED_FINAL.pdf.

[33] Latino is the term used by the U.S. Census.

39.4 percent of residents classified as Latino. At least seven of eight San Joaquin Valley communities have a lower proportion of white residents as compared to the state as a whole.[34] Merced and Tulare counties have white, non-Latino populations of 26.5 and 27.7 percent, and Latino populations of 65.6 and 61 percent, respectively.[35] Like Merced and Tulare, Kern County also demonstrates much higher Latino populations than the rest of the state, with a Latino population of 54.6 percent.

The disproportionately low-income and Latina/o/e residents of the San Joaquin Valley are exposed to the worst air quality in the state by most measures and lower income communities in the San Joaquin Valley are disproportionately subject to water contaminated with nitrates, arsenic, and 1,2,3 TCP, among others. The San Joaquin Valley is classified as an area that fails to meet several federal health-based standards for fine particulate matter ($PM_{2.5}$).[36] According to the American Lung Association, the San Joaquin Valley cities of Fresno-Madera-Hanford and Bakersfield are the second and third most polluted with respect to short-term exposure to $PM_{2.5}$.[37] The Valley cities of Bakersfield, Fresno-Madera-Hanford, and Visalia are the first, second, and third most polluted with respect to long-term exposure to $PM_{2.5}$.[38] The Valley also violates health-based standards for ozone.[39] Bakersfield, Visalia, and Fresno-Madera-Hanford are the second, third, and fourth most ozone-polluted cities in the in United States.[40] The San Joaquin Valley contains about half of California's 300 public water systems that currently serve unsafe drinking water.[41] Over the past three decades, nitrate levels in drinking water have exceeded the federal maximum contaminant level of 45 mg/L NO_3 (equivalent to 10 mg/L nitrate-N) in an estimated 24 to 40% of domestic wells in different counties in the San Joaquin Valley, compared to 10 to 15% of California's overall water supply.[42]

This pollution impacts the health and well-being of San Joaquin Valley residents.[43] Short-term exposure to $PM_{2.5}$ pollution causes premature death, decreased lung function, exacerbates respiratory disease such as asthma, and causes increased hospital admissions.[44] Long-term

[34] According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[35] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[36] 80 FED. REG. 18,528 (April 7, 2015); 81 FED. REG. 2,993 (January 20, 2016); 80 FED. REG. 2,206, 2,217 (January 15, 2015).

[37] AM. LUNG ASSN., *State of the Air 2021* 37, *available at* https://www.lung.org/getmedia/17c6cb6c-8a38-42a7-a3b0-6744011da370/sota-2021.pdf.

38 *Id.* at 38.

[39] 75 FED. REG. 24409 (May 5, 2010); 77 FED. REG. 30088, 30092 (May 21, 2012).

[40] AM. LUNG ASSN., *supra* note 37 at 36.

[41] Del Real, J.A., *They Grow the Nation's Food, but They Can't Drink the Water*, N.Y. TIMES (May 21, 2019), https://www.nytimes.com/2019/05/21/us/california-central-valley-tainted-water.html.

[42] Eli Moore, et al., *The Human Costs of Nitrate-contaminated Drinking Water in the San Joaquin Valley*, PAC. INST., 11 (2011), https://pacinst.org/publication/human-costs-of-nitrate-contaminated-drinking-water-in-the-san-joaquin-valley/.

[43] The COVID-19 pandemic has made exposure to particulate matter even more dangerous, further highlighting the health risks associated with air pollution from factory farm dairies and factory farm gas. Xiao Wu et al., *Air pollution and COVID-19 mortality in the United States: Strengths and limitations of an ecological regression analysis*, 6 SCI. ADVANCES 1 at 1-2 (Nov. 4, 2020), https://advances.sciencemag.org/content/6/45/eabd4049.

[44] AM. LUNG ASSN., *supra* note 37 at 37-38.

exposure can cause asthma and decreased lung function in children, increased risk of death from cardiovascular disease, and increased risk of death from heart attacks.[45] Nitrates in drinking water can cause serious illness and death in infants ("blue baby syndrome") and are linked to pregnancy complications and birth defects, Sudden Infant Death Syndrome, and respiratory tract infections and a number of different cancers in adults and children.[46]

CARB has acknowledged that $PM_{2.5}$ exposure alone "is responsible for about 1,200 cases of premature death in the Valley each year."[47] San Joaquin Valley residents, who CalEnviroScreen designate a "sensitive population," experience higher rates of asthma, low birth weight, and cardiovascular disease compared to state incidence rates.[48] The California Institute for Rural Studies estimates that the costs of these air quality-related health harms total over $6 billion per year in the San Joaquin Valley.[49] This pollution also impacts residents' quality of life. For example, children in the San Joaquin Valley suffer from lack of access to outdoor recreation – on days with especially poor air quality, which occurred 40 days in Kern County in 2018, local authorities recommend that schools hold recess indoors.[50]

III. CARB MUST EXCLUDE BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LCFS OR IN THE ALTERNATIVE AMEND THE REGULATION TO ACCURATELY ACCOUNT FOR THE FULL CARBON INTENSITY OF THESE FUELS AND PROHIBIT CREDITS FROM NON-ADDITIONAL REDUCTIONS.

The LCFS violates sections 38560.5, 38562(b), 38562(d)(2), 38562.5 of the Health & Safety Code because it fails to achieve the maximum technologically feasible and cost-effective emissions reductions, fails to maximize additional environmental benefits, fails to ensure additionality of reductions, and exacerbates harms associated with industrial animal agriculture, including toxic air contaminants and dangerous water pollution. These failures prevent the state from maximizing greenhouse gas emissions reductions from transportation fuels and constitute a failure to use best scientific practices, as required by section 38562(e). Moreover, they harm San

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[45] *Id*. at 38-39.
[46] WIS. DEP'T OF HEALTH SERV., *Infant Methemoglobinemia (Blue Baby Syndrome)*, https://www.dhs.wisconsin.gov/water/blue-baby-syndrome.htm (last updated Mar. 12, 2021).
[47] CAL. AIR RES. BD., *Clean-air plan for San Joaquin Valley first to meet all federal standards for fine particle pollution* (Jan. 24, 2019), https://ww2.arb.ca.gov/news/clean-air-plan-san-joaquin-valley-first-meet-all-federal-standards-fine-particle-pollution.
[48] *Indicators Overview*, CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/indicators#:~:text=Sensitive%20population%20indicators%20measure%20the,of%20their%20age%20or%20health (last visited Oct. 21, 2021); *see* AM. LUNG ASSN., *supra* note 37 at 23; Ashley E. Larsen et al., *Agricultural pesticide use and adverse birth outcomes in the San Joaquin Valley of California*, 6 NATURE COMMC'N 1, AT 4-8 (2007); Amy M. Padula et al., *Traffic-Related Air Pollution and Risk of Preterm Birth in the San Joaquin Valley of California*, 24(12) ANN EPIDEMIOL 1, 6-9; *see also* Robbin Marks, Nat. Res. Def. Council, *Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health* (2001), https://www.nrdc.org/sites/default/files/cesspools.pdf.
[49] Lisa Kresge and Ron Strochlic, *Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health*, CAL. INST. FOR RURAL STUDIES 8, (Jul. 2007).
[50] Brendan Borrell, *California's Fertile Valley is Awash with Air Pollution*, MOTHERJONES (Dec. 10, 2018), https://www.motherjones.com/environment/2018/12/californias-fertile-valley-is-awash-in-air-pollution/. *See also Policies and Procedures for Poor Outdoor Air Quality Days*, SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DIST., http://www.valleyair.org/programs/ActiveIndoorRecess/intro.htm (last visited Oct. 12, 2021).

Joaquin Valley communities with increased air and water pollution from factory farm dairies subsidized by the LCFS – harms the Legislature sought to address when it enacted AB 32 and AB 197.[51] For all of these reasons, CARB should amend the LCFS to exclude all fuels derived from biomethane from swine and dairy manure.[52] If CARB fails to do so, it must at a minimum amend the regulation to capture the full life cycle of associated greenhouse gas emissions in both the established Tier 1 pathway and the customized Tier 2 pathways and amend the regulation to ensure credited reductions are additional.[53]

A. The fuel pathways for biomethane from dairy and swine manure fail to achieve the maximum technologically feasible and cost-effective emissions reductions.

AB 32 mandates that the early action measure regulations adopted by CARB "shall achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit."[54] CARB explicitly premised the adoption of the LCFS regulation on this mandate.[55] As written and in practice, however, the LCFS regulation does not incentivize, let alone achieve, the maximum emissions reductions in this sector due to the program's inflation of carbon intensity values for factory farm gas. These inflated credit values are the result of CARB's narrow interpretation of the life cycle emissions for factory farm gas. Moreover, CARB's failure to ensure that credited emissions reductions are additional to what otherwise would have occurred inject invalid credits into the overall market and allow fuel producers to emit more pollution.

By setting overly narrow system boundaries for the life cycle analysis of factory farm gas, the LCFS fails to account for emissions associated with a true "well-to-wheels" analysis, exaggerating the emissions reductions attributed to this fuel. AB 32 requires that market-based compliance mechanisms only credit "additional" emissions reductions, and thus exclude reductions already required by law or that otherwise would occur.[56] However, CARB has allowed the LCFS program to award credits generated from non-additional reductions at factory farms. Factory farm gas projects rely on multiple sources of revenue from grant programs, federal programs, and the Aliso Canyon settlement – all of this supplementary revenue renders reductions from factory farm gas projects either partially or fully non-additional, yet CARB has made no effort to prevent these non-additional credits from entering the market.

Because CARB has allowed grossly inflated carbon intensity scores to distort the market, and allowed non-additional reductions to generate credits, the LCFS perversely incentivizes bigger dairy and pig operations to generate more methane. As a result, credit revenue from dairy factory

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[51] CAL. HEALTH & SAFETY CODE § 38501 (the Legislature named the "exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems" as potential adverse impacts of climate change.)
[52] CAL. CODE REGS. TIT. 17 § 95488.3; CAL. CODE REGS. TIT. 17 § 95488.9(f)(1). *See* proposed amendments in Appendix A.
[53] *See* proposed amendments in Appendix B.
[54] CAL. HEALTH & SAFETY CODE § 38560.5.
[55] CAL. AIR RES. BD., RES. 19-27, (Nov. 21, 2019).
[56] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

farm gas can be a more reliable income stream than milk revenue, propping up this high-emissions industry and further polluting nearby communities. Additionally, the financial windfall from these over-valued credits is traded to offset emissions from LCFS deficit holders. Together and separately, each of these violations undermines the LCFS program and constitutes a failure to achieve the maximum technologically feasible and cost-effective emissions reductions from transportation fuels in violation of AB 32.

1. The fuel pathways for biomethane from dairy and swine manure fail to incorporate life-cycle emissions, leading to inflated credits.

The LCFS over-values credits awarded to factory farm gas operations because the program omits significant emissions from the factory farm gas life cycle. Neither the established Tier 1 nor the customized Tier 2 pathways for biomethane from dairy and swine manure capture the greenhouse gas emissions associated with the full life cycle of factory farm gas. The pathways ignore both upstream and downstream emissions. In addition to setting overly narrow system boundaries, the factory farm gas life cycle analyses fail to properly account for the fact that the methane purportedly captured in the production of factory farm gas is intentionally created, resulting in an even more misleading accounting of associated climate harms. When the resulting inflated credits are traded, they allow LCFS deficit holders to achieve less than the required maximum technologically feasible and cost-effective reductions.

The LCFS requires a full "well-to-wheels" life cycle analysis to account for all emissions associated with a given fuel.[57] Such well-to-wheels accounting requires Tier 2 pathways to include "a description of all fuel production feedstocks used, including all pre-processing to which feedstocks are subject."[58] Likewise, applicants must provide:

> a detailed description of the calculation of the pathway CI. This description must provide clear, detailed, and quantitative information on process inputs and outputs, energy consumption, greenhouse gas emissions generation, and the final pathway carbon intensity, as calculated using CA-GREET3.0. Important intermediate values in each of the primary life cycle stages shall be shown. *Those stages include but are not limited to feedstock production and transport*; fuel production, fuel transport, and dispensing; co-product production, transport and use; waste generation, treatment and disposal; and fuel use in a vehicle.[59]

Feedstocks are the raw materials processed into fuel. The feedstock for factory farm gas is manure. Therefore, emissions from manure production and "pre-processing" must be included in the life cycle analysis for Tier 2 applicants. But the LCFS and CARB's implementation does not require their inclusion. For example, CalBioGas Kern Cluster's recent application begins the data-listing portion of its lifecycle analysis with the Dairy Livestock Input Data table.[60] This table does not provide an adequate analysis of the feedstock production energy input. In fact, this lifecycle

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[57] CAL. CODE REGS. TIT. 17 § 95481(a)(66).
[58] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(2).
[59] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(B) (emphasis added).
[60] CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

analysis contains no analysis pertaining to the emissions from the generation and processing of manure to produce the feedstock.

Accounting for the greenhouse gas emissions from the production and "pre-processing" of dairy or pig manure must include the inputs and infrastructure necessary to sustain a dairy cow or a pig: its food and water, the methane animals produce through enteric fermentation, the construction and maintenance of the lagoons required to hold manure, trucking livestock and other inputs, combustion of fuels at the dairy facility for electricity, and more. But the LCFS factory farm gas pathways only begin after the production of the manure itself, leaving out all upstream emissions generated formulating that manure.[61]

The regulation further enumerates that, "for fuels utilizing agricultural crops for feedstocks, the description [of feedstocks in the life cycle analysis report] shall include the agricultural practices used to produce those crops. This discussion shall cover energy and chemical use, typical crop yields, feedstock harvesting, transport modes and distances, storage, and pre-process (such as drying or oil extraction)."[62] In the Tier 2 pathways for ethanol production, this provision has been interpreted to include production and pre-processing of corn, the feedstock for ethanol. Similarly, the LCFS requires pathways that utilize organic material to "demonstrate that emissions are not significant beyond the system boundary of the fuel pathway," upon request.[63] Yet in the case of factory farm gas, none of the production and pre-processing of the feedstock is considered, making it an outlier in the LCFS program and out of compliance with section 95488.7.

The failure to include production and pre-processing of manure when calculating life cycle emissions is even more problematic because a common feed for dairy cows in California is distillers grains, a "co-product" of ethanol production. The designation of distillers grains as a "co-product" allows ethanol producers to split the emissions from corn production between the ethanol and distillers grains by weight, decreasing ethanol's carbon intensity in the LCFS analysis.[64] One ethanol industry blog noted that "the biggest factor for most of the low-CI scoring [ethanol] plants is the proportion of wet distillers grains sold locally."[65] Distillers grains are granted the "co-product" designation by virtue of the revenue they generate when sold as animal feed but because LCFS factory farm gas pathways do not account for production and pre-processing of manure, the emissions associated with distillers grains are never accounted for by the LCFS at all despite its

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[61] CAL. AIR RES. BD., *Compliance Offset Protocol Livestock Projects* (Nov. 14, 2014), Table 4.1, Description of all GHG Sources, GHG Sinks, and GHG Reservoirs; *see also* CAL. AIR RES. BD., Response to Animal Defense Legal Fund Comment, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/new_temp_carb_response.pdf (CARB arguing that "Emissions from existing CAFO operations are accounted for, but do not include emissions associated with enteric methane and animal feed use because these emissions should more appropriately be allocated to and associated with the preexisting underlying, non-fuel product stream, and are thus excluded from the system boundary in the Board approved Tier 1 Calculator.")

[62] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(2).

[63] CAL. CODE REGS. TIT. 17 § 95488.9(f)(2)(B).

[64] CAL. AIR RES. BD., *Tier 1 Simplified CI Calculator Instruction Manual: Starch and Fiber Ethano*l (Aug. 13, 2018), *available at* https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

[65] Susanne Retka Schill, *Meeting the California Low Carbon Challenge*, ETHANOL PROD. MAGAZINE (Feb. 8, 2016), http://ethanolproducer.com/articles/13000/meeting-the-california-low-carbon-challenge.

role in two transportation fuel life cycles.[66] Some ethanol plants also incorporate factory farm gas from dairies as a process fuel, further lowering the ethanol's carbon intensity.[67] These "negative" upstream emissions from factory farm gas and negative downstream emissions from the use of distillers grains as dairy feed both reduce the LCFS carbon intensity of ethanol, which would likely not receive credits otherwise.

While downstream emissions from distillers grains in ethanol production are accounted for by excluding them from that fuel's carbon intensity calculation, the by-product of dairy and swine factory farm gas, digestate – which would *increase* the carbon intensity of factory farm gas – remains largely unaccounted for, even though the LCFS requires all Tier 2 pathway application lifecycle analyses to include:

> a description of all co-products, byproducts, and waste products associated with production of the fuel. That description shall extend to all processing, such as drying of distiller's grains, applied to these materials after they leave the fuel production process, including processing that occurs after ownership of the materials passes to other parties.[68]

Demonstrably, any storage, land-application, or composting of digestate falls within the meaning of the term 'process,' but the LCFS does not require, and no factory farm gas lifecycle analyses include emissions from digestate.

The process of anaerobic digestion can result in "changes in the manure composition" that alter ammonia (NH_3) and nitrous oxide (N_2O) emissions, depending upon the management strategy used.[69] In the United States, liquid effluent from factory farm gas production is primarily applied to land as fertilizer and digestate solids are composted and then land applied or used for bedding on-farm (See Figure 4 in Appendix C).[70] Digestate land application and composting result in emissions of nitrous oxide, which has a global warming potential 265 to 298 times that of carbon dioxide.[71] A recent study found that digested solids that were composted released such significant

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[66] Somerville, Scott, Daniel A. Sumner, James Fadel, Ziyang Fu, Jarrett D. Hart, and Jennifer Heguy, *By-Product Use in California Dairy Feed Has Vital Sustainability Implications*, ARE UPDATE 24(2) (2020) 5, University of California Giannini Foundation of Agricultural Economics.

[67] For example, a Tier 2 ethanol pathway for a plant in Pixley, California uses biomethane from dairies as a process fuel to transform starch from corn into ethanol. *GFP Ethanol, LLC dba Calgren Renewable Fuels GREET Pathway for the Production of Ethanol from Corn and Fueled by NG and Biogas from Two Local Dairy Digesters* (Sept. 20, 2018), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/t2n-1279_report.pdf.

[68] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(8).

[69] Michael A. Holly et al., *Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture*, 239 ECOSYSTEMS AND ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007.

[70] Ron Alexander, *Digestate Utilization in The U.S.*, 53 BIO CYCLE 56 (Jan. 2012), https://www.biocycle.net/digestate-utilization-in-the-u-s/. Mohanakrishnan Logan & Chettiyappan Visvanathan, *Management strategies for anaerobic digestate of organic fraction of municipal solid waste: Current status and future prospects*, 37 WASTE MGT. & RES. 27, 27 (Jan. 28, 2019), https://doi.org/10.1177/0734242X18816793.

[71] Holly, *supra* note 69 at 411. Alun Scott & Richard Blanchard, *The Role of Anaerobic Digestion in Reducing Dairy Farm Greenhouse Gas Emissions*, 13 SUSTAINABILITY 2 (Mar. 1, 2021) https://doi.org/10.3390/su13052612; *Understanding Global Warming Potentials*, ENV'T PROT. AGENCY, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials (last visited Oct. 21, 2021).

nitrous oxide emissions relative to undigested manure solids that the climate benefits of the captured methane from the digestion process were cancelled out.[72] Additionally, many operators choose to store digestate in open-air lagoons. Open-air storage can release methane, potentially negating methane captured during digestion, as well as ammonia, which is harmful to nearby communities in the San Joaquin Valley and a $PM_{2.5}$ precursor.[73]

Despite the significant emissions associated with digestate and the high global warming potential of methane and nitrous oxide, the LCFS fails to fully account for this inevitable by-product of factory farm gas production. Digestate treatment and storage is within the Tier 1 system boundary for anaerobic digestion of dairy and swine manure (described as "effluent"), but the pathway does not contemplate emissions associated with effluent after storage.[74] In contrast to Tier 1, the Tier 2 system boundary in the CA GREET3.0 calculator includes emissions from "AD Residue Applied to Soil," in other words, digestate that is land applied.[75] In practice, however, digestate is not mentioned in several recent Tier 2 applications for cluster projects.[76] Further, in responding to a comment criticizing a project's lack of accounting for digestate emissions, the applicant responded in a letter to CARB that "land application of effluent is outside of the scope of the project."[77] These contradictory descriptions of the system boundary as related to digestate highlight an inconsistent approach to the quantification of emissions from digestate. Moreover, neither the pathways nor the project application materials seem to account for digestate uses other than land application. This excludes any emissions associated with the solids composting. By failing to account for downstream emissions associated with land application and the massive nitrous oxide emissions from solids composting, CARB's life cycle analysis omits significant greenhouse gas emissions from factory farm gas production and further inflates the factory farm gas credit value.

The factory farm gas life cycle analyses also fail to include downstream emissions associated with transport. The LCFS factory farm gas pathways mention, but do not require reporting of inputs to calculate emissions generated from the refining and transport of factory farm gas. For example, the Tier 1 Calculator for factory farm gas *can* quantify emissions leaked or

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[72] Holly, *supra* note 69 at 414, 418.
[73] *See generally* Yun Li et al., *Manure digestate storage under different conditions: Chemical characteristics and contaminant residuals*, 639 SCI. OF THE TOTAL ENV'T 19 (Oct. 15, 2018), https://doi.org/10.1016/j.scitotenv.2018.05.128 (discussing the impacts of open storage).
[74] CAL. AIR RES. BD., Tier 1 Simplified CI Calculator Instruction Manual: Biomethane from Anaerobic Digestion of Dairy and Swine Manure (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.63225775.1254208748.1633995805-239480191.1598055085.
[75] *LCFS Life Cycle Analysis Models and Documentation: California GREET3.0 Model,* CAL. AIR RES. BD., https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation (last visited July 29, 2021).
[76] *See* CAL. AIR RES. BD., *Fuel Pathway Table: Current Fuel Pathways*, *available at* https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities (last visited Oct. 19, 2021).
[77] Letter from Michael D. Gallo, Gallo Cattle Company Regarding "Tier 2 Pathway Application: Application No. B0089" (June 26, 2020), on file with CAL. AIR RES. BD., https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/b0089_response.pdf.

vented from the digester and associated pipeline infrastructure—but the applicant is not *required* to calculate it.[78]

In addition to the failure to account for various upstream and downstream emissions from factory farm gas production, the LCFS life cycle analyses do not address the fact that these emissions are associated with *intentionally created* methane. LCFS factory farm gas pathways are intended to credit "reduction[s] of greenhouse gas emissions achieved by the voluntary capture of methane" or "avoided methane emissions."[79] This structure is premised on the idea that the manure used to produce the gas is unavoidable waste, whose emissions would not otherwise be diverted. But the massive quantity of manure methane emissions that CARB seeks to mitigate is the result of the intentional liquification of the manure, one of multiple manure management methods. While necessary to produce factory farm gas, the production of vast quantities of liquified manure is by no means an inevitable result of dairy or pig farming.[80] Alternative manure management techniques are available. Techniques such as solid-liquid separation, scrape and vacuum collection of manure, composting, and pasture-based practices are all viable methods of manure management that would avoid the methane emissions caused by open-air lagoons of liquid manure. Preliminary findings from CARB's Dairy and Livestock Greenhouse Gas Emissions Working Group indicate that these methods of manure management may offer more cost-effective methane emissions reductions than anaerobic digestion and may deliver additional environmental and health benefits, such as reduced impact on water quality.[81] Avoiding manure generation and reducing the amount of manure that has to be managed is the best way to protect human and animal health, along with the environment (see Figure 3 in Appendix C on Waste Management Hierarchy).[82] But the LCFS program does the opposite of promoting dairy manure avoidance or even lower-emissions manure management practices. Instead, the LCFS program has created a new revenue stream for factory farms based on the manure itself – the source of the methane the program seeks to reduce – incentivizing the production and liquification of manure as though it were a cash crop.

Additionally, "even RNG from waste methane can have negative climate impacts relative to the most likely alternative of flaring, not venting, the methane."[83] Flaring, like other forms of combustion, converts methane to carbon dioxide, reducing the net emissions impact. Flaring is a ubiquitous, low cost means of reducing methane. Though flaring is not a sustainable means to

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[78] CAL. AIR RES. BD., *Tier 1 Simplified CI Calculator Instruction Manual: Biomethane from Anaerobic Digestion of Dairy and Swine Manure* 1, 8–9, 13–14 (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.153600376.1744114239.1608082460-1114251839.1598731081.
[79] CAL. CODE REGS. TIT. 17 § 95488.9(f).
[80] *Animal Agriculture in the U.S. – Trends in Production and Manure Management*, LIVESTOCK AND POULTRY ENV'T LEARNING CMTY. (Mar. 5, 2019), https://lpelc.org/animal-agriculture-in-the-u-s-trends-in-production-and-manure-management/.
[81] CAL. AIR RES. BD., *Findings and Recommendations: Subgroup 1: Fostering Markets for Non-digester Projects, Senate Bill 1383 Dairy and Livestock Working Group* 3 (Oct. 12, 2018), https://ww2.arb.ca.gov/sites/default/files/2020-11/dsg1_final_recommendations_11-26-18.pdf.
[82] A reduction of waste is the preferred management method in the Environmental Protection Agency's waste management hierarchy for decision-making. *Waste Management Hierarchy and Homeland Security Incidents,* ENV'T PROT. AGENCY, https://www.epa.gov/homeland-security-waste/waste-management-hierarchy-and-homeland-security-incidents (last visited Oct. 12, 2021).
[83] Emily Grubert, *At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates*, 15 084041 ENV'T RES. LETTERS Aug. 2020, 2.

reduce emissions, it should be the baseline to which any emissions reductions associated with anaerobic digestion are compared.

Moreover, because factory farm gas can be sold as a fuel and used to generate significant supplemental revenue from LCFS credits, over time "it is not only possible but expected…to increase methane production beyond what would have happened anyway."[84] Any manure production that has been incentivized by LCFS credit revenue will also result in intentionally created methane, which according to one recent study, *is always GHG-positive*.[85]

Finally, the Agro-Ecological Zone Emissions Factor (AEZ-EF) used to measure emissions from land-use change by CA-GREET3.0, and therefore by Tier 2 applicants, fails to account for the full impacts from the industrial dairy and pig facilities producing factory farm gas.[86] CARB's Executive Officer may require fuel producers to include six specific "feedstock/finished biofuel combinations," in their calculations.[87] These feedstocks include corn, sugarcane, sorghum grain ethanol, soy, canola, and palm biomass-based diesel.[88] Apart from land-use change related to livestock grazing (which is rarely relevant to industrial livestock operations), the AEZ-EF model does not address the land-use change associated with industrial dairy farming which are required for the production of factory farm gas.[89]

The overly narrow life cycle analysis in the factory farm gas pathways not only undermines the program's capacity to incentivize reductions, but violates AB 32's mandate that "[T]he state board shall rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by this section."[90] Scientific literature provides a more complete account of greenhouse gases emitted during the life cycle of factory farm gas produced from dairy and pig facilities. These analyses incorporate emissions from feed production, enteric fermentation, farm management and operations, and the treatment, use, or disposal of digestate residues produced during anaerobic digestion in addition to manure management emissions.[91] Omitting these essential stages from the LCFS factory farm gas pathways neglects a significant portion of emissions involved in producing

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[84] *Id.* at 5.
[85] *Id*. at 4.
[86] CAL. CODE REGS. TIT. 17 § 95488.3.
[87] CAL. CODE REGS. TIT. 17 § 95488.3(d).
[88] *Id*.
[89] Richard J. Pelvin et al., *Agro-ecological Zone Emission Factor (AEZ-F Model): A model of greenhouse gas emissions from land-use change for use with AEZ-based economic models* 3, 31 (Feb. 21, 2014), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/lcfs_meetings/aezef-report.pdf.
[90] CAL. HEALTH & SAFETY CODE § 38562 (e). In Resolution 19-27, CARB itself stated that the LCFS "was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective reductions in GHG emissions from transportation fuel used in California." CAL. AIR RES. BD., RES. 19-27, *supra* note 55.
[91] *See, e.g.,* E. M. Esteves et al., *Life cycle assessment of manure biogas production: A review,* 218 J. CLEAN PROD. 411–423 (2019), https://doi.org/10.1016/j.jclepro.2019.02.091; E. Cherubini et al., *Life cycle assessment of swine production in Brazil: a comparison of four manure management systems*, 87 J. CLEAN PROD. 68–77 (2015), https://doi.org/10.1016/j.jclepro.2014.10.035; V. Paolini et al., *Environmental impact of biogas: A short review of current knowledge*, 53, J. ENV'T SCI. HEALTH A 899–906 (2018), https://doi.org/10.1080/10934529.2018.1459076.

manure and, as a result, the pathway treats manure as if it is produced from thin air or as if lagoons of liquid manure occur naturally in the San Joaquin Valley. [92]

The LCFS regulation mandates a full accounting of the aggregate life cycle emissions from a given fuel. In CARB Resolution 19-27, the agency reiterated that the "[d]etermination of a fuel's energy demand and carbon intensity value is based on a "well-to-wheel" analysis, which includes production and processing, distribution, and vehicle operation.[93] And yet the factory farm gas pathways leave glaring gaps in the life cycle analysis beyond the narrow system boundaries. The premise that manure originates in manure lagoons ready for capture with no attendant emissions defies logic, yet CARB has embraced this to create an absurdly low carbon intensity value and inflated credit generating industry.

2. The fuel pathways for biomethane from dairy and swine manure fail to ensure that credited emissions reductions are additional to reductions that would have otherwise occurred.

The LCFS prohibits awarding credits for emissions reductions that are already required by law.[94] As a market-based compliance mechanism, however, the LCFS must also prohibit the award of credits for "any other greenhouse gas emission reduction that otherwise would occur."[95] While CARB promulgated the LCFS as an early action measure, CARB designed and implemented the LCFS as a market-based compliance mechanism. CARB itself described the LCFS as a market-based mechanism when promulgating amendments to the LCFS:

> The LCFS is a market-based approach designed to reduce the carbon intensity of transportation fuels by 10 percent by 2020, from a 2010 baseline. It is important to note that the Cap-and-Trade Program and the LCFS program have complementary, but not identical programmatic goals: Cap-and-Trade is designed to reduce greenhouse gasses from multiple sources by setting a firm limit on GHGs; the LCFS is designed to reduce the carbon intensity of transportation fuels. As a market-based, fuel-neutral program, the LCFS provides regulated parties with flexibility to achieve the most cost-effective approach for reducing transportation fuels' carbon intensity. . . .

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[92] A Naranjo et al., *Greenhouse Gas, Water, and Land Footprint Per Unit of Production of the California Dairy Industry Over 50 Years*, 103 J. DAIRY SCI. 3760–3773 (2020), https://www.journalofdairyscience.org/article/S0022-0302(20)30074-6/pdf; C. Alan Rotz et. al., *The Carbon Footprint of Dairy Production Systems Through Partial Life Cycle Assessment*, 93 J. DAIRY SCI. 1266–1282 (2010), https://doi.org/10.3168/jds.2009-2162; C. Alan Rotz, *Modeling Greenhouse Gas Emissions from Dairy Farms*, 101 J. DAIRY SCI. 6675–6690 (2018) https://www.sciencedirect.com/science/article/pii/S002203021731069X.

[93] CAL. AIR RES. BD., RES. 19-27, *supra* note 55; *see also* CAL. AIR RES. BD., *Appendix D: Draft Environmental Analysis* (Jan. 2, 2015), https://ww2.arb.ca.gov/sites/default/files/classic/regact/2015/lcfs2015/lcfs15appd.pdf.

[94] *See* CAL. CODE REGS. TIT. 17 § 95488.9(f)(1)(B) ("A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that… the baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.")

[95] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

> ARB staff disagrees that the LCFS is fundamentally a command-and-control system. The LCFS is a fuel-neutral, market-based program that does not give preference to specific transportation fuels and instead bases compliance on a system of credits and deficits based on each fuel's carbon intensity. Carbon intensity (CI) is a measure of the GHG emissions associated with the various production, distribution, and consumption steps in the "life cycle" of a transportation fuel. It is difficult to respond with depth to this assertion because the commenter provides no specifics to support the claim that the LCFS is not market-based. Notably, the commenter does not describe what components of the program could be considered command-and-control.[96]

Additionally, CARB's descriptions of the LCFS program closely parallel the statute's definition of "market-based compliance mechanism." The defintion states in relevant part that a market-based compliance mechanism is: "A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases."[97] CARB explains that the LCFS has a "market for credit transactions," where "entities with credits to sell can opt to pledge credits into the market and entities needing credits must purchase their pro-rata share of these pledged credits."[98] CARB explains that credits are generated relative "to a declining CI benchmark for each year."[99] The LCFS exhibits many if not most of the features of a market-based compliance mechanism, including a Cap-and-Trade allowance-like system with yearly declinations,[100] transaction rules,[101] recordkeeping and auditing requirements,[102] an account system to manage credit transfers – the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS),[103] and a portal that applicants must use to demonstrate compliance,[104] among others. In addition to CARB's interpretation, designation, and treatment of the program as a market-based

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[96] CAL. AIR RES. BD., *Final Statement of Reasons for Rulemaking, Including Summary of Comments and Agency Response* 679-681 (2015), *available at* https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/fsorlcfs.pdf. *See also* CAL. AIR RES. BD., *Responses to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations* at B4-42 (2018), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/rtcea.pdf (CARB responding, "Because the LCFS is a market-based mechanism…"); CAL. AIR RES. BD., *Staff Discussion paper: Renewable Natural Gas from Dairy and Livestock Manure 6* (April 13, 2017), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/041717discussionpaper_livestock.pdf (in which CARB staff note in 2017 discussion paper that additionality requirements for the LCFS *are* intended to be identical to those of the compliance offset protocol, "ensure any crediting is for GHG reductions resulting from actions not required by law or beyond business as usual").

[97] CAL. HEALTH & SAFETY CODE § 38505(k). Note that this is one of two definitions provided.

[98] CAL. AIR RES. BD., *LCFS Basics* (2019), *available at* https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited Oct. 12, 2021).

[99] *Low Carbon Fuel Standard: About*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Oct. 12, 2021).

[100] *See* CAL. CODE REGS. TIT. 17 §§ 95482 – 95486.

[101] *See* CAL. CODE REGS. TIT. 17 § 95491.

[102] *See* CAL. CODE REGS. TIT. 17 § 95491.1.

[103] CAL. CODE REGS. TIT. 17 § 95483.2(b). ("The LRT-CBTS is designed to support fuel transaction reporting, compliance demonstration, credit generation, banking, and transfers.").

[104] *See* CAL. AIR RES. BOARD, *Low Carbon Fuel Standard – Annual Reporting and Verification User Guide* 3-4 (Aug. 9, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/Reporting_and_Verification_User_Guide.pdf.

mechanism and the overall structure of the regulation evincing the same, the designation of California's LCFS as a market-based mechanism is ubiquitous in academic and technical literature.[105]

Because the LCFS is a market-based compliance mechanism, section 38562(d)(2) of the Health & Safety Code requires that CARB ensure greenhouse gas emissions reductions in the LCFS are "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur."[106] Additionality requirements are essential for market-based programs that operate with a declining emissions benchmark, like the LCFS. Because regulated parties are permitted to emit above the benchmark so long as they offset these emissions with the purchase of credits, the LCFS must ensure that credits reflect reductions that are additional to claim a net reduction. The additionality requirement enumerated in the LCFS currently is far too narrow. It requires only that reductions are "additional to any legal requirement for the capture and destruction of biomethane."[107] This weak language incorporates only one of the two prongs required by AB 32 and does not ensure that reductions are additional to those from other LCFS incentives. CARB should grant this petition and amend the LCFS to include the broader additionality requirement.

As implemented to date, the LCFS program allows generation, sale, and use of factory farm gas credits that are plainly not additional when the methane reductions attributed to these LCFS credits result from, and are attibuted to, other programs and revenue sources. The LCFS 1) allows the same emissions reductions to be counted and credited by multiple emission reductions programs; and 2) awards credits to facilities receiving public funding for anaerobic digesters and related infrastructure, even when that funding is contingent on the construction of this equipment.

Numerous state and federal funding opportunities, incentives, and other subsidies are available for anaerobic digestors at factory farms. The Aliso Canyon Mitigation Agreement that CARB negotiated with Southern California Gas Company (SoCalGas) legally requires SoCalGas to pay for methane reductions at factory farm dairies in California.[108] The parties intended the agreement to mitigate the harms from the most damaging man-made greenhouse gas leak in United States history – SoCalGas' ruptured well that released at least 109,000 metric tons of methane before it was sealed.[109] SoCalGas funds the construction of digesters, which are intended to mitigate the leaked methane, and receives "mitigation credits" for the associated emissions reductions. The conditions of the agreement legally require changes intended to reduce emissions

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[105] *See, e.g.,* CENTER FOR CLIMATE AND ENERGY SOLUTIONS, *Policy Considerations for Emerging Carbon Programs* 2 (June 2016), https://www.c2es.org/wp-content/uploads/2016/06/emerging-carbon-programs.pdf (describing Low Carbon Fuel Standards as an example of a market-based policy option, specifically of a baseline-and-credit program); *Regional Activities*, NATIONAL LOW CARBON FUEL STANDARD PROJECT, https://nationallcfsproject.ucdavis.edu/regional-activities/ (stating California's "LCFS is a market-based mechanism") (last visited Oct. 12, 2021).

[106] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

[107] CAL. CODE REGS. TIT. 17 § 95488.9(f)(1).

[108] *People v. Southern California Gas Company,* Case Nos. BC602973 & BC628120, Appendix A to Consent Decree, Mitigation Agreement, *available at* https://www.arb.ca.gov/html/aliso-canyon/aliso-canyon-mitigation-agreement.pdf?_ga=2.146452402.708596706.1633463951-1172357510.1559256345.

[109] CAL. AIR RES. BD., *Responses to Frequently Asked Questions: Aliso Canyon Litigation Mitigation Settlement*, https://ww3.arb.ca.gov/html/aliso-canyon/aliso-canyon-faqs.pdf?_ga=2.67705041.1139070712.1533833674-1489205872.1532954259.

and yet at least eight facilities that receive this funding have also applied for LCFS credits for biomethane production. California Bioenergy sought LCFS credits for the S&S, Moonlight, Hamstra, Trilogy, Maple, T&W, BV Dairy, and Western Sky dairies.[110] These eight dairies are among seventeen that participate in the Aliso Canyon Mitigation Agreement.[111] Under no circumstances should mitigation for the Aliso Canyon disaster simultaneously qualify for credits generated and used in the LCFS.

Furthermore, the Legislature has appropriated public funds from the Greenhouse Gas Reduction Fund (GGRF) for several years to secure climate benefits. The California DDRDP, funded through the GGRF, provides funding for factory farm gas infrastructure. The California Department of Food and Agriculture describes the DDRDP as "financial assistance for the installation of dairy digesters in California, which will result in reduced greenhouse gas emissions."[112] Since 2015, the DDRDP has funded 117 dairy projects through the DDRDP, for a total of $195,025,884, and for which the CDFA claims 21,023,793 MTCO2e of methane reductions.[113] CARB also claims these reductions in a report to the Legislature on the climate benefits from these grants.[114] At least eight of these dairy projects, and likely many more, have received DDRDP grants and sought LCFS credits. For instance, California Bioenergy sought LCFS credits for the S&S, Moonlight, Hamstra, Trilogy, Maple, T&W, BV Dairy, and Western Sky dairies, all of which received DDRDP grants.[115] Importantly, the DDRDP purports to limit how grant monies may be used, but it does not prohibit a project from generating LCFS credits.[116]

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[110] *See* CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0185, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_cover.pdf; CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

[111] CAL. AIR RES. BD., *Aliso Canyon Natural Gas Leak, List of dairies involved in the mitigation agreement*, https://www.arb.ca.gov/html/aliso-canyon/aliso-canyon-mitigation-project-dairy-sites.pdf?_ga=2.216890962.535652136.1632321175-1949797088.1632171356.

[112] *Dairy Digester Research & Development Program*, CAL. DEPT. OF FOOD & AG., https://www.cdfa.ca.gov/oefi/ddrdp/ (last visited Oct. 19, 2021).

[113] CAL. DEPT. OF FOOD & AG., *CDFA Dairy Digester Research and Development Program Flyer (Sept. 2021)*, *available at* https://www.cdfa.ca.gov/oefi/ddrdp/docs/DDRDP_flyer_2021.pdf. (A list of all project recipients can be found at CAL. DEPT. OF FOOD & AG., *Dairy Digester Research and Development Program Project-Level Data (Sept. 17, 2021),* https://www.cdfa.ca.gov/oefi/DDRDP/docs/DDRDP_Project_Level_Data.pdf.)

[114] CAL. CLIMATE INVESTMENTS, *2021 California Climate Investments Annual Report*, Table 2 (2021), *available at* http://ww2.arb.ca.gov/sites/default/files/cap-and-trade/auctionproceeds/2021_cci_annual_report.pdf.

[115] *See* CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0185 *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_cover.pdf; CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

[116] *See 2020 DDRDP Request for Grant Applications,* CAL. DEPT. OF FOOD & AG., https://www.cdfa.ca.gov/oefi/DDRDP/docs/2020_DDRDP_RGA_Public_Comments.pdf (last visited Oct. 5, 2021) ("Once a project has been awarded funds, the project may not: • Change or alter their biogas end-use during the project term. • Change the herd size beyond the limits established by the existing dairy operation's permits during the project term. • Change ownership of the dairy and/or partnership entities… • Duplicate equipment or activities that will receive funding from the California Public Utilities Commission (CPUC) pilot project authorized by California Health and Safety Code Section 39730.7(d)(2) (e.g., interconnection costs). *Note: Biogas conditioning and clean-up costs are allowable under the DDRDP.* • Commercial dairy operations that have already accepted, or plan to accept a grant award by CDFA's Alternative Manure Management Program (AMMP).") (emphasis added). Note that by allowing DDRDP funds to cover upgrade costs and other costs that the CPUC incentives program cannot, the CDFA has ensured that factory farm gas projects can benefit from multiple funding sources.

Other public funds authorized by the Legislature subsidize factory farm gas projects seeking to interconnect with utility natural gas pipelines.[117] This additional source of funds quickly became oversubscribed, prompting the California Public Utilities Commission to double the size of the program, all paid for with proceeds from sales of Cap-and-Trade allowances.[118] The California Public Utilities Commission went a step further, proposing in 2017 that participants in the SB1383 dairy biomethane Pilot Program could avoid the costs associated with gas production equipment, specifically gathering lines and "treatment equipment."[119] In what would be a major break with California energy precedent, ratepayers got to foot the bill.[120]

Projects receiving public funds should not, under the principles of additionality, also generate LCFS credits that allow emissions elsewhere; in this situation public funds essentially allow a transportation fuel deficit holder to emit more greenhouse gases and allow the factory farm gas project to generate a financial windfall. Under no circumstances did the Legislature intend for this perverse result to occur.

This is not a hypothetical concern: CARB recently proposed approval of Tier 2 Pathway applications B0185 and B0198 for eight dairy digester projects that have received both Dairy

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[117] *See* CAL. PUB. UTILITIES COMM'N, Decision Adopting the Standard Renewable Gas Interconnection and Operating Agreement, R.13-02-008 COM/CR6/jnf at 12 (Dec. 17, 2020), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M356/K244/356244030.PDF ("D.15-06-029 created a $40 million monetary incentive program "to encourage potential biomethane producers to build and operate biomethane projects within California that interconnect with the utilities" in accordance with AB 1900 (Gatto, 2012). This monetary incentive program was subsequently codified by AB 2313 (Williams, 2016)…The $40 million approved by the CPUC for the monetary incentive program is currently fully subscribed and there is a wait list for an additional $38.5 million worth of project funding.").

[118] *See Id.* at 14 ("After weighing the benefit of increased biomethane capture and use against the modest reduction in the California Climate Credit necessary to fully fund all existing biomethane projects, including those on the waitlist, we find it appropriate to provide an additional $40 million in funding from Cap-and-Trade allowance proceeds for the monetary incentive program to fund the biomethane projects that are currently on the wait list, bringing total funding to $80 million.").

[119] Decision establishing the implementation and selection framework to implement the dairy biomethane pilots required by Senate Bill 1383 at 7-8 (Dec. 18, 2017), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352373.PDF (". . . [T]he biomethane producers should own and operate the digesters and the biogas collection lines and treatment equipment to remove hydrogen sulfide and water from the raw biogas. Although we do not allow utilities to own these facilities, the costs associated with the biogas collection lines and treatment equipment will be recovered from the transmission rates of utility ratepayers through a reimbursement to the dairy biomethane producer. Natural gas utilities will own and operate all facilities downstream of the biogas conditioning and upgrading facilities, including pipeline laterals from such facilities, to the point of receipt and any pipeline extensions.").

[120] *Id.* ("Historically the costs of gathering, gas conversion to pipeline quality specifications, transportation from a gas production site to a conversion facility, transportation from the conversion facility to the pipeline, and pipeline interconnection costs have been borne by California natural gas producers as part of the commodity cost of gas since the late 1980s, as 'gathering costs' that the CPUC has ruled should be assigned to gas producers . . . . For the purposes of the Dairy Pilots, and consistent with the language of SB 1383, we are allowing cost recovery of the biogas collection lines owned by dairy biomethane producers, and allowing utilities to own and operate pipelines that carry biomethane from biogas conditioning and upgrading facilities to existing utility transmission systems and the interconnection facilities, without changing the requirements of D.89-12-016 for non-renewable natural gas producers . . . .").

Digester Research Development Program (DDRDP) and Aliso Canyon settlement funds.[121] Both programs claim credit for the methane reductions associated with the digester projects. If the LCFS system grants credits for these same reductions and allows a deficit holder to use those credits to demonstrate compliance with the LCFS, the reductions will be without question not additional. This absurd result allows excessive emissions and CARB must grant this petition to ensure LCFS program integrity.[122]

A wide range of other state and federal financial assistance is available to factory farms to support the construction and implementation of factory farm gas systems. This public financing comes in the form of grants, "production incentive payments, low-interest financing, tax exemptions and incentives, and permitting assistance."[123] The California Energy Commission provides funding for factory farm gas development through its Natural Gas Research and Development program.[124] The program provides $100 million annually to various fuel transportation projects, including factory farm gas.[125] The Environmental Quality Incentives Program (EQIP) is a federal program that provides matching funds for agricultural operations to contract with Natural Resources Conservation Service to develop technology or infrastructure with environmental benefits, including the construction of anaerobic digestion infrastructure.[126] The Rural Energy for America Program also provides federal funds to develop factory farm gas systems. *See* 7 U.S.C. § 8107.

The LCFS is demonstrably and avowedly a market-based compliance mechanism and is thus properly subject to the requirements of section 38562(d)(2). As the forgoing demonstrates,

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[121] These dairy digester projects also may participate in the California Public Utilities Commission pilot projects, as California Bioenergy projects, which would confer additional public funds. *See* CAL. PUB. UTILITIES COMM'N, Press Release: CPUC, CARB, and Department of Food and Agriculture Select Dairy Biomethane Proejcts to Demonstrate Connection to Gas Pipelines (December 3, 2018), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M246/K748/246748640.PDF.

[122] This has caused confusion in Tier 2 application comments. For example, in comments on several applications, the Chair of the Board for the Kings County Board of Supervisors commented to ask how these applicants could participate in the LCFS without double counting reductions, given that they also participated in bioMAT. CARB did not respond to the comments. *See* CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 61 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0106_verboon_comments.pdf (commenting on Tier 2 Application B0106); CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 60 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0105_verboon_comments.pdf (commenting on Tier 2 Application B0105); CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 59 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b104_verboon_comments.pdf (commenting on Tier 2 Application B0104).

[123] CAL. DAIRY CAMPAIGN, *Economic Feasibility of Dairy Digester Clusters in California: A Case Study* 45, (June 2013) https://archive.epa.gov/region9/organics/web/pdf/cba-session2-econ-feas-dairy-digester-clusters.pdf.

[124] *Natural Gas Research and Development Program*, CAL. ENERGY. COMM'N., https://www.energy.ca.gov/sites/default/files/2019-05/naturalgas_faq.pdf (last visited Oct. 18, 2021).

[125] *Clean Transportation Program*, CAL. ENERGY. COMM'N., https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program (last visited Oct. 18, 2021).

[126] Environmental Quality Incentives Program, NAT'L RES. CONS. SERVICE, https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/programs/financial/eqip/.

private and public funding either have been or could be used to reduce methane emissions from pig and dairy facilities.[127] The LCFS should not allow fuel producers to generate credits from such non-additional reductions that deficit holders then use to justify their excess emissions, undermining the integrity of the LCFS program.

3. CARB's crediting of non-additional reductions and the inflated credit value from CARB's failure to account for the full quantity of life-cycle emissions both incentivize increased manure generation and manure liquification and constitute a failure to achieve the maximum technologically feasible and cost-effective greenhouse gas emissions.

Including inflated credits and credits for non-additional reductions contravenes the fundamental purpose of the LCFS: to reduce greenhouse gas emissions associated with transportation fuels. Inflated credits and credits for non-additional reductions have the effect of increasing manure generation and liquification, and its associated greenhouse gas emissions. Additionally, by purchasing inflated credits, deficit generators can more easily meet their compliance obligations without reducing their emissions. As a result of these deficiencies, the LCFS fails to achieve the maximum technologically feasible and cost-effective emissions reductions.

The factory farm gas industry is currently made profitable by the LCFS and similar programs. In fact, "[w]ell over 50% of the revenue from most projects generating credits comes from the [LCFS and Federal RIN] credits."[128] A recent report by a private investment firm on the promising growth prospects for factory farm gas concluded that "operators are not in the business of producing RNG, they are in the business of monetizing RNG's environmental attributes through various federal and state programs."[129] This is by design: the goal of the LCFS factory farm gas pathways is to incentivize the development of factory farm gas as an alternative fuel. This goal assumes incentivizing development of factory farm gas will result in a net decrease in manure methane emissions. But this assumption – the result of the deficient life cycle analysis and inclusion of non-additional reductions – is mistaken.

Increased profitability and growth of the factory farm gas industry does not necessarily entail a reduction in manure methane emissions from participating factory farms. Due to the poor design of the LCFS pathways for factory farm gas, the program encourages not only capture of manure methane, as intended, but increased production of that methane. Revenue from LCFS credits is an increasingly enticing source of potential profit for many factory farms. In the case of

[127] For this reason, LCFS credits also should not be issued to facilities that already operate digesters to produce low-CI electricity but seek to convert to producing biomethane, as no truly additional emissions reductions occur upon switching fuel production pathways.

[128] Annie AcMoody & Paul Sousa, *Western United Dairies, Interest in California Dairy Manure Methane Digesters Follows the Money*, CoBANK, at 4, (Aug. 2020), https://www.cobank.com/documents/7714906/7715329/Interest-in-California-Dairy-Manure-Methane-Digesters-Follows-the-Money-Aug2020.pdf/be11d7d6-80df-7a7e-0cbd-9f4ebe730b25?t=1603745079998.

[129] STIFEL EQUITY RESEARCH, *Energy & Power – Biofuels: Renewable Natural Gas, A Game-Change in the Race for Net-Zero* (March 8, 2021), *available at* https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/60ad5a8802a04b71ca252414/1621973643907/Stifel+RNG+Analysis.pdf.

industrial dairy operations, these inflated credits provide certainty for operators seeking to maintain or expand herd sizes by providing significant additional income to supplement volatile milk revenue.[130] In 2017, CARB itself "assume[d] that California's LCFS credits [would] contribute revenue of $865,000" (assuming $100 per metric ton of CO_2).[131] The average LCFS credit price has increased significantly since this estimate was made, with 2020 prices hovering around $200 per metric ton of CO_2 (see Figure 5 in Appendix C). As a result, LCFS credits can be a more reliable income stream than milk. The LCFS not only encourages the development of factory farm gas systems but entrenches the underlying factory farms and even incentives expansion of these operations – the very sources of manure methane the factory farm gas credits are intended to reduce.

LCFS credits derive their value from recipients' ability to sell these credits to LCFS participants that generate deficits. Deficit-generating facilities include producers of conventional, high carbon intensity fuels such as gasoline and diesel fuels. This means that the life cycle analysis deficiencies and granting of credits for non-additional reductions not only incentivize increased emissions from factory farms, but also function to allow emissions in other transportation fuel industries.

Additionally, because economies of scale for anaerobic digesters favor larger herd sizes, factory farm gas producers have an incentive to produce more liquid manure, by either increasing herd size or participating in a digester cluster. This is the case for factory farm gas from both cows and pigs. In California, where most digesters use manure from lagoons to produce gas for pipeline transport, the technology requires a minimum of 2,000 cows to be economically feasible.[132] Scale is central to making the technology investment profitable, and "each additional 1,000 cows reduce the cost per cow of digester projects by 15-20%."[133] EPA AgSTAR admits that most methane digesters "are not economically viable until greater than 10,000 hogs are incorporated."[134]

The programmatic distortions described in parts III(A)(1) and (2) will drive the expansion of factory farms to supply factory farm gas, intentionally creating greenhouse gas emissions and localized pollution. CARB should rescind the factory farm gas pathways and preclude factory farm

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[130] The milk price that dairy farmers receive has fluctuated considerably over the past two decades while costs have remained relatively constant. In 2015 and 2016, dairies experienced negative average residuals (see Table 2 in Appendix C). In 2017, annual milk revenue from "a farm with 2,000 cows producing 230 hundredweight per cow per year (the average in the San Joaquin Valley)" totaled nearly $7.6 million based on the milk price of $16.50 per hundredweight. After factoring in 2017 cost estimates by the California Department of Food and Agriculture (CDFA), the "net revenue at the typical dairy in the southern San Joaquin Valley amounted to zero." *See* Justin Ellerby, CAL. CENTER FOR COOP. DEV., *Challenges and Opportunities for California's Dairy Economy* 5 (2010); William Matthews and Daniel Sumner, *Contributions of the California Dairy Industry to the California Economy in 2018*, UNIV. OF CAL. AGRIC. ISSUES CENTER 17-18 (2019), https://aic.ucdavis.edu/wp-content/uploads/2019/07/CMAB-Economic-Impact-Report_final.pdf; Hyunok Lee. & Daniel A. Sumner, *Dependence on policy revenue poses risks for investments in dairy digester,* 72 CAL. AG. 226-235, 231 (2018), https://doi.org/10.3733/ca.2018a0037.

[131] Hyunok Lee & Daniel A. Sumner, *supra* note 130 at 232.

[132] GLOBAL DATA POINT, *California Incentives Spur Dairy Manure Methane Digester Developments*, GALE: BUSINESS INSIGHTS (Doc. No. A631672444) (Aug. 6, 2020).

[133] *Id.*

[134] ENV'T PROT. AGENCY, *AgSTAR, Project Development Handbook: A Handbook for Developing Anaerobic Digestion/Biogas Systems on Farms in the United States* 7-2, n. 58, https://www.epa.gov/sites/default/files/2014-12/documents/agstar-handbook.pdf (3rd Ed.).

gas from the LCFS program. In the alternative, CARB must amend the regulation to ensure that the carbon intensity values account for the full life cycle of dairy and pig facility emissions, including production and pre-processing of manure feedstock and downstream emissions associated with digestate land application and composting, and prohibit credits from non-additional reductions.

B. The fuel pathways for biomethane from dairy and swine manure fail to maximize additional environmental benefits and interfere with efforts to improve air quality.

The California Legislature directed CARB to design regulations in a manner that considers overall societal benefits, including other benefits to the environment and public health, and ensure that activities taken pursuant to the regulations do not interfere with the state's efforts to improve air quality.[135] The Legislature also declared, in enacting AB 32, that it intended that CARB design reduction measures in a manner that "maximizes additional environmental and economic cobenefits for California, and complements the state's efforts to improve air quality."[136] But so long as the LCFS program includes factory farm gas and incentivizes factory farm expansions and the resulting air pollution, it cannot maximize environmental benefits or improve air quality. Moreover, given these impacts, CARB has not adequately considered overall societal costs in the regulation's design.

Monetizing a waste stream, like manure, does not eliminate that waste. The material impacts of manure (and later digestate) remain, whether or not it generates revenue for confined animal feeding operations. Nearby communities must still contend with the harms from the production, transportation, storage, and processing of this waste. If anything, monetizing a waste stream like manure exacerbates these harms by disincentivizing waste reduction. Incentivizing larger herd sizes and the liquification of more manure exacerbates existing pollution to air, water, and land, and the associated public health harms from industrial dairy and pig facilities, in addition to increased greenhouse gas emissions.[137] Additionally, factory farm gas technology creates new and additional environmental and public health harms, including through the storage, composting, and land application of digestate.

The 3.9 million residents of the San Joaquin Valley face increased health risks from breathing polluted air.[138] Industrial dairy operations emit the ammonia that contributes to the some

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[135] CAL. HEALTH & SAFETY CODE § 38562(b)(4) ("Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."); CAL. HEALTH & SAFETY CODE § 38562(b*)(*6) ("Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."). *See also* CAL. HEALTH & SAFETY CODE § 38562.5 (making section 38562(b) applicable to regulations adopted to achieve reductions beyond the statewide greenhouse gas emissions limit).

[136] CAL. HEALTH & SAFETY CODE § 38501.

[137] *EPA Activities for Cleaner Air - San Joaquin Valley,* U.S. ENV'T PROT. AGENCY, https://www.epa.gov/sanjoaquinvalley/epa-activities-cleaner-air (last updated Mar. 6, 2019).

[138] Rory Carroll, *Life in San Joaquin valley, the place with the worst air pollution in America*, THE GUARDIAN (May 13, 2016), https://www.theguardian.com/us-news/2016/may/13/california-san-joaquin-valley-porterville-pollution-poverty.

of the worst long-term and short-term $PM_{2.5}$ pollution in the United States, which causes health problems such as asthma and has been linked to premature death as described *supra* in part II.[139] Industrial dairies are also the largest source of volatile organic compounds (VOCs), which contribute to the Valley's ozone (smog) air pollution crisis.[140] The digestate from factory farm gas production can emit even more hazardous VOCs during storage. An analysis of digestate from pig manure identified nearly 50 VOCs, 22 of which are labeled hazardous by the EPA.[141] Of these 22 hazardous VOCs, "8 were identified to be or likely to be carcinogenic, and 14 were identified to be harmful to other human organs or systems."[142]

Biogenic and anthropogenic emissions of VOCs and nitrogen oxides (NOx) both form ground-level ozone, the concentration of which is "directly affected by temperature, solar radiation, wind speed and other meteorological factors."[143] VOCs from corn silage at dairies alone would be the largest source in the Valley, with such emissions forming more ozone than the VOCs emitted by passenger vehicles.[144] Breathing in ground-level ozone can trigger a variety of dangerous health problems like throat irritation, chest pain, and congestion. It can also lead to severe lung damage, making infants and the elderly more vulnerable to health effects.[145] Ozone causes respiratory inflammation, increased hospital admissions for respiratory illness, decreased lung function, enhanced respiratory symptoms for people with asthma, increased school absenteeism, and premature mortality.[146] Evidence indicates that "adverse public health effects occur following exposure to elevated levels of ozone, particularly in children and adults with lung disease."[147] The San Joaquin Valley is classified as an extreme ozone nonattainment area for the 1997 and 2008 8-hour ozone standards.[148]

Industrial dairies are also the largest source of ammonia.[149] Factory farm gas production adds even more ammonia to San Joaquin Valley air: ammonia emissions from digestate increased 81% relative to raw manure.[150] Anaerobic digestion causes this increase in ammonia emissions, "due to an increased concentration of ammoniacal nitrogen."[151] In addition to its unpleasant odor,

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139 *Id.*
140 *See* SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DIST., *2016 Plan for the 2008 8-Hour Ozone Standard, Appendix B*, *available at* http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/b.pdf.
141 Yu Zhang et al., *Characterization of Volatile Organic Compound (VOC) Emissions from Swine Manure Biogas Digestate Storage*, 10 ATMOSPHERE 1, 7 (2019), https://doi.org/10.3390/atmos10070411.
142 *Id.* at 8.
143 73 FED. REG. 16436, 16437 (March 27, 2008).
144 *See* Cody J. Howard, et al., *Reactive Organic Gas Emissions from Livestock Feed Contribute Significantly to Ozone production in Central California*, 44 ENV'T SCI. TECHNOL. 7 2309–2314 (2010), https://pubs.acs.org/doi/abs/10.1021/es902864u.
145 *Id.*
146 73 Fed. Reg. 16436, 16440 (March 27, 2008).
147 83 FED. REG. 61346, 61347 (November 29, 2018).
148 75 FED. REG. 24409 (May 5, 2010); 77 FED. REG. 30088, 30092 (May 21, 2012).
149 SAN JOAQUIN VALLEY AIR CONTROL DIST., 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, Appendix B and Appendix G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf and http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
150 *See* Holly, et al., *Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land disposal*, AG., ECOSYSTEMS AND ENV'T 239 (2017) 410–419, https://www.researchgate.net/publication/313731233_Greenhouse_gas_and_ammonia_emissions_from_digested_and_separated_dairy_manure_during_storage_and_after_land_application.
151 *Id.*

which degrades quality of life for nearby residents, ammonia "is corrosive and can be a powerful irritant to skin, eyes, and digestive and respiratory tissues."[152] Ammonia also reacts with oxides of nitrogen to form ammonium nitrate, the most significant component of the San Joaquin Valley's $PM_{2.5}$ pollution problem.[153] Homes located within a quarter mile of a dairy confined animal feeding operation have experienced higher concentrations of both ammonia and particulate matter.[154] In addition to the harms of PM2.5 describes above, larger particles of dust pollution from factory farm dairies also carry harmful allergens and endotoxins to nearby homes.[155] Endotoxins are a "powerful inflammatory agent" that can interact with other components and lead to respiratory issues, and allergens can worsen asthma symptoms.[156] A study in rural Washington found that higher exposure to pollution from confined animal feeding operations was associated with degraded lung function in children with asthma living nearby.[157]

Depending on the physical characteristics (temperature, pH, total solid content) and the speed and frequency of the mixing process used to treat it, digestate from factory farm gas production can release dangerous concentrations of hydrogen sulfide.[158] High hydrogen sulfide emission levels are associated with a total solid content of seven percent, "which is the most appropriate for pumping and mixing of dairy manure."[159] Increasing the speed and frequency of mixing while in storage can also contribute to higher hydrogen sulfide emissions from digestate.[160] These emissions can have severe impacts on human health, particularly farm workers, and can even lead to death.[161] Furthermore, hydrogen sulfide may be detected on fields where manure is sprayed for fertilizer, and the gaseous substance can be dispersed by the wind.[162] Hydrogen sulfide gas is a respiratory tract irritant and in higher concentrations or with longer exposure, it can cause a pulmonary edema.[163] The acute symptoms of hydrogen sulfide exposure include nausea, headaches, delirium, disturbed equilibrium, tremors, convulsions, and skin and eye irritation.[164]

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[152] D'Ann L. Williams et al., *Airborne cow allergen, ammonia and particulate matter at homes vary with distance to industrial scale dairy operations: an exposure assessment*, 10 ENV'T HEALTH 1, 3 (2011), https://doi.org/10.1186/1476-069X-10-72.

[153] SAN JOAQUIN VALLEY AIR CONTROL DIST., *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards*, Appendix B and Appendix G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf and http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.

[154] D'Ann Williams et al., *Cow allergen (Bos d2) and endotoxin concentrations are higher in the settled dust of homes proximate to industrial-scale dairy operations*, 26 J. EXPOSURE SCI. ENV'T EPIDEMIOLOGY 42, 46 (2016) https://doi.org/10.1038/jes.2014.57.

[155] *Id.*

[156] *Id.* at 42.

[157] Christine Loftus et al., *Estimated time-varying exposures to air emissions from animal feeding operations and childhood asthm*a, 223 INT. J. OF HYGIENE AND ENV'T HEALTH 192 (2020) https://doi.org/10.1016/j.ijheh.2019.09.003.

[158] Fetra J. Andriamanohiarisoamanana et al., *Effects of handling parameters on hydrogen sulfide emission from stored dairy manure*, 154 J. ENV'T MGMT. 110, 112-115 (2011), https://doi.org/10.1016/j.jenvman.2015.02.003.

[159] *Id.* at 115.

[160] *Id.* at 114.

[161] *Id.* at 110.

[162] *See* Agency for Toxic Substances and Disease Registry, Toxicological Profile for Hydrogen Sulfide and Carbonyl Sulfide, DEP'T OF HEALTH AND HUMAN SERVICES 27-138 (2016), https://www.atsdr.cdc.gov/toxprofiles/tp114.pdf; *See also* Amy Schultz et al., *Residential proximity to concentrated animal feeding operations and allergic and respiratory disease*, 130 ENV'T INT. 104911, 1 (2019), https://doi.org/10.1016/j.envint.2019.104911.

[163] *See* Agency for Toxic Substances and Disease Registry, *supra* note 162 at 27-138.

[164] *Id.*

Finally, inhalation of high concentrations or long-term exposure to hydrogen sulfide can result in extremely rapid unconsciousness and eventual death.[165]

Factory farm dairies also pollute the San Joaquin Valley's groundwater, primarily through the disposal of manure by land application on crops, which causes severe public health impacts to nearby communities. The Valley contains about half of California's 300 public water systems that currently serve unsafe drinking water.[166] This number does not include private wells and water systems serving fewer than 15 households. Unsafe water systems are concentrated in small towns and unincorporated communities.[167] Common pollutants in water from factory farm runoff include nitrogen, phosphorus, heavy metals, and pharmaceuticals.[168]

Nitrate contamination of water resources is one of the most widely documented environmental impacts in California's dairy-producing regions. Most nitrate contamination comes from chemical fertilizers and animal manure applied to fields.[169] Nitrogen application often far exceeds the crops' rate of nutrient intake and the soil's ability to absorb nutrients, which then leach into groundwater.[170] A study by University of California Davis found that 96% of nitrate pollution in the region comes from nitrogen applied to cropland, a third of which is in the form of animal manure.[171] The 2019 Central Valley Dairy Representative Monitoring Program reported that nitrate concentrations exceeded the maximum contaminant level in groundwater at all of the 42 dairy facilities.[172] The program identified the application of manure to crop fields as the main source of groundwater contamination, while finding other unaccounted nitrogen sources – too many cows – at the dairy facilities contributing to the excessive nitrate contamination.[173]

Between 1999 and 2008, seven out of eight counties in the San Joaquin Valley had above-average rates of Sudden Infant Death Syndrome which can be caused by nitrate contamination. 70% of San Joaquin Valley households believed their tap water to be unsafe when surveyed in 2011, and nitrate pollution still appears to be rising.[174] A 2016 study that mapped out the mass flows of nitrogen in the San Joaquin Valley, estimated that the health costs of total nitrate leaching to groundwater caused $500 million per year in health damages.[175] Application of biogas digestate, either as a liquid or composted solids,[176] will continue the trend in nitrate contamination in the San

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[165] *Id.*

[166] J.A. Del Real, *They Grow the Nation's Food, but They Can't Drink the Water*, N.Y. TIMES (May 21, 2019), https://www.nytimes.com/2019/05/21/us/california-central-valley-tainted-water.html.

[167] *Id.*

[168] JoAnn Burkholder et al., *Impacts from Waste from Concentrated Animal Feeding Operations on Water Quality*, 115 ENV'T HEALTH PERSPECTIVES 308, 308 (2007), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC1817674/.

[169] *The Sources and Solutions: Agriculture*, U.S. ENV'T PROT. AGENCY, https://www.epa.gov/nutrientpollution/sources-and-solutions-agriculture (last updated July 30, 2020).

[170] *Id.*

[171] Harter et al., *Addressing Nitrate in California's Drinking Water with a Focus on Tulare Lake Basin and Salinas Valley Groundwater*, CENTER FOR WATERSHED SCI., UNIV. CAL., DAVIS, 17 (2012).

[172] CENTRAL VALLEY DAIRY REP. MONITORING PROG., *Summary Representative Monitoring Report* at 8 (Revised 2020).

[173] *Id.*

[174] *Id.* at 28.

[175] Ariel I. Horowitz et al., *A multiple metrics approach to prioritizing strategies for measuring and managing reactive nitrogen in the San Joaquin Valley of California*, 11 ENV'T RES. LETTERS 1, 11 (2016).

[176] Roger Nkoa, *Agricultural benefits and environmental risks of soil fertilization with anaerobic digestates: A review*, 34 AGRON. SUSTAIN. DEV. 473, 473–492 (2014).

Joaquin Valley in particular, compounding the increase from the LCFS's subsidizing increased manure production.

In addition to the emissions from digestate storage and land application, certain Tier 2 anaerobic digester facilities generate additional air pollutants using factory farm gas to power internal combustion engines that generate electricity onsite.[177] According to a 2015 study commissioned by CARB, this form of electricity generation produces criteria air pollutants, like NOx and particulate matter.[178] Furthermore, the study found this technology would increase NOx emissions by 10 percent, exacerbating air quality in the Valley, in violation of CARB's duty to ensure that its programs do not interfere with efforts to reduce air pollution.[179] The San Joaquin Valley Unified Air Pollution Control District also documents criteria pollutant emissions from electricity generation from factory farm gas.

For example, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site.[180] And this project, as permitted by the Air District with required pollution control technology, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM10, and 3.18 tons/year of VOC.[181] Compared to a natural gas combined cycle plant in Avenal permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, SOx, and VOC emissions per unit of electricity generated.[182] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase offset emission reduction credits for the toxic air pollution emitted.[183] This facility *increases* air pollution. But California Bioenergy also sought for LCFS credits under a Tier 2 pathway application for the Lakeview Dairy project.[184] By allowing polluting facilities like Lakeview Dairy to generate credits for "renewable" natural gas, despite the harmful health impacts associated with emissions from the use of factory farm gas to generate electricity, CARB ignores its statutory obligation not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[185]

Because the LCFS has resulted in and will continue to incentivize an increase in dangerous pollution to the air, water, and land of the San Joaquin Valley, it fails to comply with section

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177 Arnaud Marjollet, *District Notice of Preliminary Decision*, San Joaquin Valley: Air Pollution Control (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf; *see also* CAL. AIR RES. BD., Staff Summary, Tier 2 Pathway Application B0104, Lakeview Dairy, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
178 Marc Carreras-Sospedra et al., *Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California* at 9-10 (Feb. 2015), https://ww2.arb.ca.gov/sites/default/files/classic//research/apr/past/11-307.pdf.
179 *Id*. at 4, 13.
180 Arnaud Marjollet, *supra* note 177.
181 *Id*. at 14.
182 Brent Newell, *Comments filed to California Energy Commission*, 4 (July 11, 2017), *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=220110&DocumentContentId=29811; Arnaud Marjollet, *supra* note 177 at 20.
183 *Id*.
184 CAL. AIR RES. BD., Staff Summary, Tier 2 Pathway Application B0104, Lakeview Dairy, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
185 CAL. HEALTH & SAFETY CODE § 38562 (b).

38562(b) (4) and (6) of the Health and Safety Code. Additionally, the LCFS program violates the Legislature's intent, expressed in section 38501(h) of the Health and Safety Code, to maximize additional environmental benefits. CARB should grant this petition and exclude factory farm gas from the program to address these violations.

IV. CARB MUST EVALUATE AND AMEND THE LCFS TO REMEDY ITS DISPROPORTIONATE ADVERSE AND CUMULATIVE IMPACTS ON LOW-INCOME AND LATINA/O/E COMMUNITIES IN VIOLATION OF STATE AND FEDERAL LAW.

CA 11135 and Title VI of the Civil Rights Act impose an affirmative duty on CARB to ensure that its policies and practices do not have a discriminatory impact on the basis of race.[186] CA 12955 additionally prohibits any practice or program that has a discriminatory effect on members of protected classes with respect to housing opportunities, including with respect to the use and enjoyment of dwellings.[187] AB 32 requires CARB to ensure any activities undertaken in compliance with the statute do not disproportionately impact low-income populations, consider the social costs of greenhouse gas emissions, and design regulations in a manner that is equitable. CARB must assess and prevent the disparate impacts imposed by the LCFS to avoid further harm to communities and to comply with California and federal law.

A. LCFS credits and the subsequent trading of those credits incentivize activities that result in public health and environmental harms in disproportionately low-income and Latina/o/e communities, particularly in the San Joaquin Valley.

The LCFS harms communities that are disproportionately Latina/o/e and low-income. These harms stem from (1) the generation of revenue for factory farms in proportion to the amount of manure they produce, (2) the encouragement of anaerobic digestion resulting in additional environmental harms related to digestate, and (3) allowing credits to offset emissions and toxic air pollutants elsewhere in California. Each of these harms impact disproportionately low-income and Black, Indigenous, or People of Color communities.

In California, the award of LCFS credits for factory farm gas and the harms these credits incentivize are concentrated in the San Joaquin Valley.[188] Part III(A)(3) shows how the LCFS has the effect of exacerbating existing adverse impacts from factory farms by incentivizing increased production and liquification of manure. Part III(B) describes the extensive environmental and public health harms associated with the increase in liquified manure, as well as the new harms

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186 CAL. GOV'T CODE § 11135; 42 U.S.C. § 2000d.

187 CAL. GOV'T CODE § 12955.8; CAL. CODE REGS. TIT. 2 § 12161.

188 The San Joaquin Valley hosts 89% of the state's dairy cow population, and all but one of its counties are ranked nationally for milk sales (See Table 3, Appendix C). CAL. DEP'T OF FOOD AND AGRIC., Small Dairy Climate Action Plan 1 (2018), https://www.cdfa.ca.gov/oefi/research/docs/CDFA_Summary_of_Final_Report.pdf; *See* Lori Pottinger, *California's Dairy Industry Faces Water Quality Challenges*, Public Institute of California (May 20, 2019), https://www.ppic.org/blog/californias-dairy-industry-faces-water-quality-challenges/ (all 117 DDRDP projects are in the Valley).

from digestate. Incentivizing expansion of factory farms may also negatively affect community and economic growth.[189] Part II shows that San Joaquin Valley communities impacted by these new and exacerbated harms are disproportionately Latina/o/e and disproportionately low-income. Part II also describes the preexisting cumulative harms impacting these communities: San Joaquin Valley residents experience "the worst" air pollution nationally, and high levels of drinking water and groundwater contamination, largely due to agricultural runoff.[190]

The LCFS's market-based structure shapes the distribution of adverse impacts imposed by its incentives. In addition to the harmful activities incentivized at credit-generating factory farm gas facilities, the LCFS facilitates harm by the deficit-generating facilities that purchase credits. In order to provide for the trading of credits and deficits, LCFS treats greenhouse gas emissions as fungible. This approach allows CARB to justify the greenhouse gas emissions from gasoline and diesel, for example, in excess of the program's benchmark when the producers of these fuels purchase the equivalent credits. This is viewed by CARB as a positive attribute of the LCFS program because it "lets the market decide" how to achieve the targeted emissions reductions. But treating emissions as fungible ignores the localized impacts of co-pollutants associated with the production, transport, and combustion of various transportation fuels. These harms do not disappear simply because a gasoline producer pays to justify its polluting practices. The sale of factory farm gas credits to LCFS deficit generators prolongs their ability to pollute, rather than make direct emissions reductions.

Given that LCFS deficit generators include producers of conventional fuels, such as gasoline, diesel, and compressed natural gas, there is good reason to believe that LCFS deficit generating industries may disproportionately harm low-income and Black, Indigenous, and People of Color – specifically Latina/o/e – communities. The vast majority of California oil and gas production is concentrated in the San Joaquin Valley and around Los Angeles.[191] California communities living in proximity to oil and gas extraction are known to be disproportionately low income and Latina/o/e.[192] In the San Joaquin Valley, the oil and gas industries are concentrated in Kern County, where residents are subject to the cumulative harms of petrochemical extraction in

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[189] Research indicates that "concentration and industrialization of agricultural production removes more money from the community of which the farm is located than when smaller farms operate in the area." CHELSEA MACMULLAN, HUMANE SOC'Y OF THE U.S., DAIRY CAFOS IN CALIFORNIA'S SAN JOAQUIN VALLEY at 26 (2007), https://www.humanesociety.org/sites/default/files/archive/assets/pdfs/farm/macmullan_apa-2007_final.pdf. The ratio of payroll versus emissions produced by concentrated factory farm dairies ranks worse than the petroleum industry. *Id*. at 27. Additionally, factory farm dairy employees face greater health risks because of their proximity to air pollutants and bacteria. Working in the industry has been associated with respiratory diseases such as Chronic Bronchitis, Occupational Asthma, and Pharyngitis. *Id*. at 29. Lack of access to healthcare due to language barriers or undocumented status likely exacerbates these harms. *Id*.

[190] *See* Carroll, *supra* note 138; *see also* Burkholder, *supra* note 168 at 308.

[191] Judith Lewis Mernit, *The Oil Well Next Door: California's Silent Health Hazard*, YALE ENV'T 360 (March 31, 2021), https://e360.yale.edu/features/the-oil-well-next-door-californias-silent-health-hazard ("Kern County, as the southern end of the San Joaquin Valley, produces 70 percent of California' oil; the bulk of the rest comes out of Los Angeles.")

[192] *See, e.g.* Kyle Ferrar, *People and Production: Reducing Risk in California Extraction,* FRACTRACKER ALLIANCE, (Dec. 17, 2020), https://www.fractracker.org/2020/12/people-and-production/; John C. Fleming et al., *Disproportionate Impacts of Oil and Gas Extraction on Already "Disadvantaged" California Communities: How State Data Reveals Underlying Environmental Injustice*, https://www.essoar.org/doi/pdf/10.1002/essoar.10501675.1 (concluding that 77% of permits for oil and gas wells were issued in "communities with a higher-than-average percentage of residents living in poverty and/or communities with a majority non-white population").

addition to those of factory farm dairies. As noted in part II, Kern County has seen a recent increase in LCFS applications for factory farm gas pathways. Residents of Kern County already experience higher than average rates of Chronic Lower Respiratory Disease (CLRD), asthma, and respiratory system cancers.[193] The death rate from CLRD in Kern County from 2013 to 2016 was twelve times higher than the state's CLRD death rate during the same time period.[194] Exacerbation of CLRD cases is a primary reason for CLRD-related deaths.[195] In 2015 to 2016, 31.1% of children in Kern County had been diagnosed with asthma at some point in their life, compared to 15.2% of children statewide and 13.7% and 10.3% in Los Angeles County and Sacramento County, respectively.[196]

In addition to emissions from extraction and refining of these polluting fuels, LCFS credits can also be used to offset emissions from the combustion. The co-pollutants from these emissions likely impose disproportionate adverse impacts on low-income and Black, Indigenous, and People of Color communities in California. A 2014 analysis found that exposure to $PM_{2.5}$ from cars, trucks, and buses "is not equally distributed" across California.[197] More specifically, the analysis concluded that on average, "African American, Latino, and Asian Californians are exposed to more $PM_{2.5}$ pollution from cars, trucks, and buses than white Californians. These groups are exposed to $PM_{2.5}$ pollution 43, 39, and 21 percent higher, respectively, than white Californians."[198] Additionally, "[T]he lowest-income households in the state live where $PM_{2.5}$ pollution is 10 percent higher than the state average, while those with the highest incomes live where PM2.5 pollution is 13 percent below the state average."[199] Given that California's major diesel trucking corridors, Interstate 5 and State Highway 99, both run north-south directly through the San Joaquin Valley,[200] emissions from combustion of deficit-generating transportation fuels may well impose additional cumulative impacts on the same communities impacted by dairy factory farms as well as fossil fuel extraction and refining.

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[193] Yongping Hao et al., *Ozone, Fine Particulate Matter, and Chronic Lower Respiratory Disease Mortality in the United States*, 192(3) AM. J. OF RESPIRATORY AND CRITICAL CARE MED. 337, 337–341, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4937454/.

[194] Nick Perez, *Despite decades of cleanup, respiratory disease deaths plague California county*, ENV'T HEALTH NEWS (Dec. 4, 2018) https://www.ehn.org/chronic-respiratory-disease-california-2621765230/pollution-persists.

[195] Elizabeth Oelsner et al., *Classifying Chronic Lower Respiratory Disease Events in Epidemiologic Cohort Studies*, 13 ANNALS OF THE AM. THORACIC SOC'Y 1057, 1057 (July 2016) https://doi.org/10.1513/AnnalsATS.201601-063OC.

[196] *Summary: Asthma*, KIDSDATA, https://www.kidsdata.org/topic/45/asthma/summary?gclid=Cj0KCQiAst2BBhDJARIsAGo2ldWxDuxZNs3gzxS4Qj3s048YVqkp4LWQ_nwYs7DSID4FDRTTdSsgq1waAgyxEALw_wcB (last visited Oct. 21, 2021).

[197] UNION OF CONCERNED SCI., *Inequitable Exposure to Air Pollution from Vehicles in California 1 (Feb. 2019)*, https://www.ucsusa.org/sites/default/files/attach/2019/02/cv-air-pollution-CA-web.pdf

[198] *Id.*

[199] *Id.* at 2.

[200] David Lighthall and John Capitman, *The Long Road to Clean Air in the San Joaquin Valley: Facing the Challenge of Public Engagement* 8 (Dec. 2007), CENTRAL VALLEY HEALTH POL'Y INST., https://chhs.fresnostate.edu/cvhpi/documents/cvhpi-air-quality-report07.pdf

B. CARB must amend the LCFS regulation to come into compliance with CA 11135, CA 12955, and Title VI of the Civil Rights Act of 1964 and to prevent further discrimination.

CARB has an affirmative duty under CA 11135 to ensure that its policies and practices do not disproportionately impact residents on the basis of race, color, national origin, or ethnic group identification.[201] CA 11135's prohibition on discrimination applies to the LCFS because it meets the criteria of a program that is "conducted, operated, or administered" by CARB, a California state agency.[202] CA 12955 prohibits activities that limit housing opportunities for members of protected classes, including activities and programs that interfere with the use and enjoyment of one's dwelling or that results in the location of toxic, polluting, and/or hazardous land uses in a manner that adversely impacts the enjoyment of residence, land ownership, tenancy, or any other land use benefit related to residential use. The state is subject to the prohibitions included in the Fair Employment and Housing Act.[203] Title VI of the Civil Rights Act of 1964 and implementing regulations prohibit disparate impact discrimination on the basis of race by recipients of federal funds.[204] As a recipient of federal funding, CARB is subject to Title VI.[205]

As described above, the LCFS exacerbates harms in some San Joaquin Valley communities twice over: once when it incentives the expansion of factory farm dairies and anaerobic digestion, and again when the resulting credits are sold to justify the pollution from conventional transportation fuel production, distribution, and combustion. Some (and likely all) of these harms are imposed on communities that are disproportionately Latina/o/e. Additionally, the LCFS has the effect of defeating one of the objectives of AB 32 on a discriminatory basis: to maximize additional environmental benefits and complement efforts to reduce air pollution.

Not only are there "equally effective alternative practices" to achieve the goal of reducing transportation emissions, there are alternative practices that are demonstrably both more effective and less discriminatory.[206] Reducing net greenhouse gas emissions from transportation fuels is an important and legitimate goal. Sadly, the LCFS factory farm gas pathways fail to accomplish it. Therefore, California's greenhouse gas emissions targets provide no credible justification for the LCFS's discriminatory impacts. Moreover, there are other, less harmful agricultural practices that CARB could encourage to reduce net emissions. Rather than monetize the source of greenhouse gas emissions and related co-pollutants, CARB could encourage the direct reduction of emissions at their source by supporting practices such as solid-liquid separation, scrape and vacuum

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[201] CAL. GOV'T CODE § 11135.
[202] *Id.*
[203] CA Legis. 352 (2021), CAL. LEGIS. SERV. CH. 352 (A.B. 948), amending CAL. GOVT CODE 12955; 2 CCR 12005(v); 2 CCR 12060.
[204] 42 U.S.C. §2000d; 40 C.F.R. §7.
[205] CARB has received funds EPA, including, for example, over $11.8 million in 2020 to administer the Diesel Emissions Reduction Act. Soledad Calvino, *U.S. EPA awards over $11.8 million for clean diesel projects in California*, U.S. ENV'T PROT. AGENCY (San Francisco), Aug. 30, 2020, News Release, https://www.epa.gov/newsreleases/us-epa- awards-over-118-million-clean-diesel-projects-california.
[206] *See, e.g., Elston v. Talladega Count.*, 997 F. 2d at 1413.

collection of manure, composting, and pasture-based practices. Similarly, there are less harmful policy tools that could be used to produce these reductions.[207]

CARB bears the duty to evaluate the potentially discriminatory impacts of its policies and practices and to prevent these harms in the first place, which it failed to do in the design of the LCFS regulation and fails to do on an ongoing basis. To bring the LCFS into compliance with its civil right obligations, CARB must cease and desist from operating the LCFS program in such a way that results in unlawful, discriminatory impacts as proscribed by CA Gov't Code Sections 11135 and 12955, et seq., and Title VI of the Civil Rights Act of 1964. To this end, CARB must a) conduct a disparity analysis to evaluate the program and b) amend the LCFS regulation to ensure that it does not continue to disproportionately harm low-income and Latina/o/e communities. A disparity analysis must include an evaluation of the distribution of impacts from incentives created by credit generation, direct emissions from deficit generators facilitated by the trading of LCFS credits, and the distribution of emissions from the combustion of these fuels.[208]

C. CARB failed to design the LCFS regulation in a manner that is equitable and fails on an ongoing basis to consider the social costs of greenhouse gas emissions and ensure that the LCFS does not disproportionately impact low-income communities.

AB 32 mandated several safeguards to ensure equity and protect low-income communities in California from potential adverse impacts associated with the act's implementation. Section 38562(b)(2) of California Health and Safety Code requires that CARB design regulations "in a manner that is equitable" and "[ensure] that activities undertaken to comply with the regulations do not disproportionately impact low-income communities" to the extent feasible.[209] Section 38562(b)(2) also mandates that CARB "consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."[210] Section 38562.5 further mandates that, "when adopting rules and regulations pursuant to this division to achieve emissions reductions beyond the state greenhouse gas emissions limit and to protect the state's most impacted and disadvantaged

[207] Environmental justice critiques of pollution trading schemes for their tendency to result in localized pollution that disproportionately impacts low-income and people of color communities are longstanding. *See, e.g., Environmental Justice Advocates Blast Emissions Trading Guide*, 10 INSIDE EPA'S CLEAN AIR REPORT 9, 6-7 (April 29, 1999), *available at* https://www.jstor.org/stable/48520963; Lily N. Chinn, *Can the Market Be Fair and Efficient? An Environmental Justice Critique of Emissions Trading*, 26 *Ecol. L. Quart.* 1 (1999), http://www.jstor.org/stable/24114004; Letter to the Biden-Harris Transition Team Re: EPA Administrator Appointment from Over 70 Environmental Justice Groups (December 2, 2020), *available at* https://1bps6437gg8c169i0y1drtgz-wpengine.netdna-ssl.com/wp-content/uploads/2020/12/2020-12-2-Nichols-letter.pdf.

[208] LCFS fuels originating from factory dairy farms include electricity, renewable natural gas, hydrogen, bio-compressed natural gas, bio-liquefied natural gas, and bio-liquefied-regasified-and recompressed (Bio-L-CNG). CAL. CODE REGS. TIT. 17, § 95481 (defining biogas, biomethane, and all LCFS fuels produced from biomethane).

[209] CAL. HEALTH & SAFETY CODE § 38562(b)(2). See also *Ass'n of Irritated Residents v. State Air Res. Bd.*, 206 Cal. App. 4th 1487, 1489 (2012).

[210] CAL. HEALTH & SAFETY CODE § 38562.

communities," the state board shall consider social costs.[211] CARB is currently out of compliance with each of these mandates and, accordingly, must cease and desist operation of the LCFS factory farm gas pathways unless and until it comes into compliance.

Section 38562(b)(2)'s charge to protect "low-income communities" includes "persons and families whose income does not exceed 120 percent of the area median income, adjusted for family size [...] in accordance with adjustment factors adopted and amended from time to time by the United States Department of Housing and Urban Development pursuant to Section 8 of the United States Housing Act of 1937."[212] Area median income covers "the median family income of a geographic area of the state."[213] The residents of the San Joaquin Valley are precisely the low-income communities Sections 38562 seek to protect. As demonstrated above, the LCFS factory farm gas pathways have a disproportionate adverse impact on the basis of race and income, demonstrating CARB's failure to have designed the regulations in a manner that is equitable.

Finally, 38562(b)(2) requires consideration of overall societal benefits. CARB must amend the LCFS regulation to account for this and remedy these violations to come into compliance with AB 32. In Section 38562.5 of California Health and Safety Code, social costs means "an estimate of the economic damages, including, but not limited to, changes in net agricultural productivity; impacts to public health; climate adaptation impacts, such as property damages from increased flood risk; and changes in energy system costs, per metric ton of greenhouse gas emission per year."[214] The greenhouse gas emissions and associated co-pollutants from the production of factory farm gas has significant socials costs to public health, as discussed extensively in parts III and IV(B). Amending the LCFS to account for a serious consideration of the social costs of the emissions associated with both factory farm gas and the conventional fuels that generate deficits would not only bring CARB into compliance with Section 38562.5, but it would assist CARB in understanding and evaluating the inequitable distribution of adverse impacts in a manner that supports civil rights compliance, a described above.

V. CARB'S LACK OF TRANSPARENCY DENIES THE PUBLIC THE ABILITY TO REVIEW AND CHALLENGE EXISTING REGULATIONS, INCLUDING THE LCFS PATHWAYS FOR BIOMETHANE FROM DAIRY AND SWINE MANURE.

Meaningful public participation and advocacy regarding the impacts of the LCFS program have been hindered by CARB's lack of transparency. Locations of facilities purchasing the credits generated by factory farm dairies in the San Joaquin Valley are unknown to the public and attempts to obtain trading data through the California Public Records Act has produced only heavily redacted records. Without readily available trading data, it is difficult to determine potential disparate impacts caused by both the incentives produced by credit generation and the offsetting role of credit trading within the LCFS program. Community groups and advocates should not have

[211] CAL. HEALTH & SAFETY CODE § 38562.5. Note that the 2018 amendments made the LCFS generate reductions beyond the statewide limit.
[212] CAL. HEALTH & SAFETY CODE § 50093.
[213] *Id.*
[214] CAL. HEALTH & SAFETY CODE § 38506.

to seek out this information to conduct their own analyses of CARB's potentially discriminatory policies. CARB's control over the trading data places the agency in the best position to assess the disparate impact produced by the LCFS. Moreover, CARB has a clear, affirmative duty to comply with AB 32, CA 11135, and Title VI and prevent a disparate impact from its policies and practices.

VI. CONCLUSION

Since the Legislature enacted AB 32 in 2006, both the predicted and actual climate change-related harms have become more dire.[215] The methane generated by factory farm dairies in California alone accounts for approximately 45 percent of the state's total methane emissions that contribute to these harms.[216] And the Intergovernmental Panel on Climate Change recently declared a climate code red when it called for strong, sustained, and rapid methane reductions to stabilize our climate.[217]

CARB must grant this petition and reform the LCFS. Rather than allow factory farm gas reductions to substitute for emissions increases from the transportation sector, CARB should amend the LCFS to exclude factory farm gas from this pollution trading scheme.[218] If CARB instead decides to continue allowing Big Oil & Gas to offset their transportation fuel emissions with factory farm gas, then CARB must (1) ensure that the LCFS does not inflict disparate impacts in violation of CA 11135, CA 12955, and Title VI of the Civil Rights Act; and (2) adopt all alternative LCFS amendments requested here to ensure LCFS integrity and protections for rural communities.

CARB must take this opportunity to reform a pollution trading scheme that has gone off the rails. The LCFS incentivizes more of that which it purports to control, allows inflated and illusory credits from factory farm gas to authorize more emissions from transportation fuel, refuses to acknowledge the truth that liquefied manure is intentionally created and not somehow naturally occurring awaiting only abatement, and authorizes non-additional credits generated at projects receiving massive incentives from public funds and the Aliso Canyon settlement agreement. This pollution trading scheme merely shifts emissions; it benefits Big Oil & Gas to allow more pollution from their transportation fuels. It benefits, entrenches, and expands the industrial dairy and pig industry with a revenue stream more valuable than milk. And it benefits the gas utilities that

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[215] *See, e.g.*, Thomas Fuller and Christopher Flavelle, *A Climate Reckoning in Fire-Stricken California*, N.Y. TIMES (Sept. 10, 2020), https://www.nytimes.com/2020/09/10/us/climate-change-california-wildfires.html; Christopher Flavelle, *How California Became Ground Zero for Climate Disasters*, N.Y. TIMES (Sept. 20, 2020), https://www.nytimes.com/2020/09/20/climate/california-climate-change-fires.html; Nadja Popovich, *How Severe Is the Western Drought? See For Yourself.*, N.Y. TIMES (Sept. 20, 2020), https://www.nytimes.com/interactive/2021/06/11/climate/california-western-drought-map.html.
[216] CAL. AIR RES. BD., Short-Lived Climate Pollutant Reduction Strategy 56, Figure 4 (March 2017), https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.
[217] IPCC, *Climate Change 2021: the Physical Science Basis, which represents the findings of Working Group I and its contribution to the Sixth Assessment Report*, *available at* https://www.ipcc.ch/report/ar6/wg1/.
[218] Petitioners do not suggest that methane from industrial dairy and pig facilities should be unabated. CARB has authority to adopt mandatory regulations to achieve up to a 40 percent reduction from manure methane emissions pursuant to Health & Safety Code § 39730.5.

desperately attempt to perpetuate the combustion of gas in the face of a future where electrified buildings and transportation are the only routes to achieve California's climate goals. San Joaquin Valley communities should not suffer the discriminatory effects of CARB's pollution trading scheme, and CARB should grant this petition and deliver environmental justice.

Respectfully Submitted this 27th of October, 2021,

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I. APPENDICES

A. APPENDIX A: PROPOSED AMENDMENTS TO THE LCFS TO REMOVE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE

§ 95488.3. Calculation of Fuel Pathway Carbon Intensities

(a) Calculating Carbon Intensities. Fuel pathway applicants and the Executive Officer will evaluate all pathways based on life cycle greenhouse gas emissions per unit of fuel energy, or carbon intensity, expressed in gCO2e/MJ. For this analysis, the fuel pathway applicant must use CA-GREET3.0 model (including the Simplified CI Calculators derived from that model) or another model determined by the Executive Officer to be equivalent or superior to CA-GREET3.0.

(b) CA-GREET3.0. The CA-GREET3.0 model (August 13, 2018) contains emission factors for calculating greenhouse gas emissions from site-specific inputs to fuel pathways and standard values for parts of the life cycle not included in applicant-specific data submission. The model is open source and publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and is incorporated herein by reference. CA-GREET3.0 includes contributions from the Oil Production Greenhouse Gas Estimator (OPGEE2.0) model (for emissions from crude extraction) and Global Trade Analysis Project (GTAP-BIO) together with the Agro-Ecological Zone Emissions Factor (AEZ-EF) model for land use change (LUC).

Tier 1 Simplified CI Calculators, which incorporate emission factors and life cycle inventory data from the CA-GREET3.0 model, are used to calculate carbon intensities for Tier 1 pathways. The eight Simplified CI Calculators listed below are publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and are incorporated herein by reference:

(1) Tier 1 Simplified CI Calculator for Starch and Fiber* Ethanol (August 13, 2018)

(2) Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol (August 13, 2018)

(3) Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel (August 13, 2018)

(4) Tier 1 Simplified CI Calculator for LNG and L-CNG from North American Natural Gas (August 13, 2018)

(5) Tier 1 Simplified CI Calculator for Biomethane from North American Landfills (August 13, 2018)

(6) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge (August 13, 2018)

~~(7) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste (August 13, 2018)~~

© OPGEE2.0. The OPGEE2.0 model is used to generate carbon intensities for crude oil used in the production of ultra-low sulfur diesel (ULSD) and California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).

(d) Accounting for Land Use Change. The Executive Officer calculates LUC effects for certain crop-based biofuels using the GTAP model (modified to include agricultural data and termed GTAP-BIO) and the AEZ-EF model. LUC values for six feedstock/finished biofuel combinations are provided in Table 6 below. The Executive Officer may use the same modeling framework to assess LUC values for other fuel or feedstock combinations, not currently found in Table 6, as part of processing a pathway application. Alternatively, the Executive Officer may require a fuel pathway applicant to use one of the values in Table 6, if the Executive Officer deems that value appropriate to use for a fuel or feedstock combination not currently listed in Table 6.

Table 6. Land Use Change Values for Use in CI Determination

Biofuel	LUC (gCO<2>/MJ
Corn Ethanol	19.8
Sugarcane Ethanol	11.8
Soy Biomass-Based Diesel	29.1
Canola Biomass-Based Diesel	14.5
Grain Sorghum Ethanol	19.4
Palm Biomass-Based Diesel	71.4

* Fiber in this case refers to corn and grain sorghum fiber exclusively.

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(f) Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion ~~may~~ shall not be certified.~~ With a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:~~

~~(A) A biogas control system, or digester, is used to capture biomethane from manure management on **dairy** cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.~~

~~(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.~~

B. APPENDIX B: PROPOSED AMENDMENTS TO REFORM THE LCFS PATHWAYS FOR BIOMETHANE FROM DAIRY AND SWINE MANURE

§ 95488.3. Calculation of Fuel Pathway Carbon Intensities

(a) Calculating Carbon Intensities. Fuel pathway applicants and the Executive Officer will evaluate all pathways based on life cycle greenhouse gas emissions per unit of fuel energy, or carbon intensity, expressed in gCO2e/MJ. For this analysis, the fuel pathway applicant must use CA-GREET3.0 model (including the Simplified CI Calculators derived from that model) or another model determined by the Executive Officer to be equivalent or superior to CA-GREET3.0.

(b) CA-GREET3.0. The CA-GREET3.0 model (August 13, 2018) contains emission factors for calculating greenhouse gas emissions from site-specific inputs to fuel pathways and standard values for parts of the life cycle not included in applicant-specific data submission. The model is open source and publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and is incorporated herein by reference. CA-GREET3.0 includes contributions from the Oil Production Greenhouse Gas Estimator (OPGEE2.0) model (for emissions from crude extraction) and Global Trade Analysis Project (GTAP-BIO) together with the Agro-Ecological Zone Emissions Factor (AEZ-EF) model for land use change (LUC).

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(1) Tier 1 Simplified CI Calculator for Starch and Fiber* Ethanol (August 13, 2018)

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(5) Tier 1 Simplified CI Calculator for Biomethane from North American Landfills (August 13, 2018)

(6) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge (August 13, 2018)

(7) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste (August 13, 2018)

(c) OPGEE2.0. The OPGEE2.0 model is used to generate carbon intensities for crude oil used in the production of ultra-low sulfur diesel (ULSD) and California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).

(d) Accounting for Land Use Change. The Executive Officer calculates LUC effects for certain crop-based biofuels using the GTAP model (modified to include agricultural data and termed GTAP-BIO) and the AEZ-EF model. LUC values for six feedstock/finished biofuel combinations are provided in Table 6 below. The Executive Officer may use the same modeling framework to assess LUC values for other fuel or feedstock combinations, not currently found in Table 6, as part of processing a pathway application. Alternatively, the Executive Officer may require a fuel pathway applicant to use one of the values in Table 6, if the Executive Officer deems that value appropriate to use for a fuel or feedstock combination not currently listed in Table 6.

Table 6. Land Use Change Values for Use in CI Determination

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Grain Sorghum Ethanol	19.4
Palm Biomass-Based Diesel	71.4

* Fiber in this case refers to corn and grain sorghum fiber exclusively.

(e) Accounting for life cycle emissions for all fuel pathways from manure feedstock. In calculating the carbon intensity of any fuel derived from manure feedstock, the Executive Officer shall include all upstream and downstream greenhouse gas emissions from all activities associated with manure production, including but not limited to feed emissions, mobile and stationary source combustion emissions, enteric emissions, emissions from composting digestate solids, emissions following land application, and indirect source emissions.

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(f) Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:

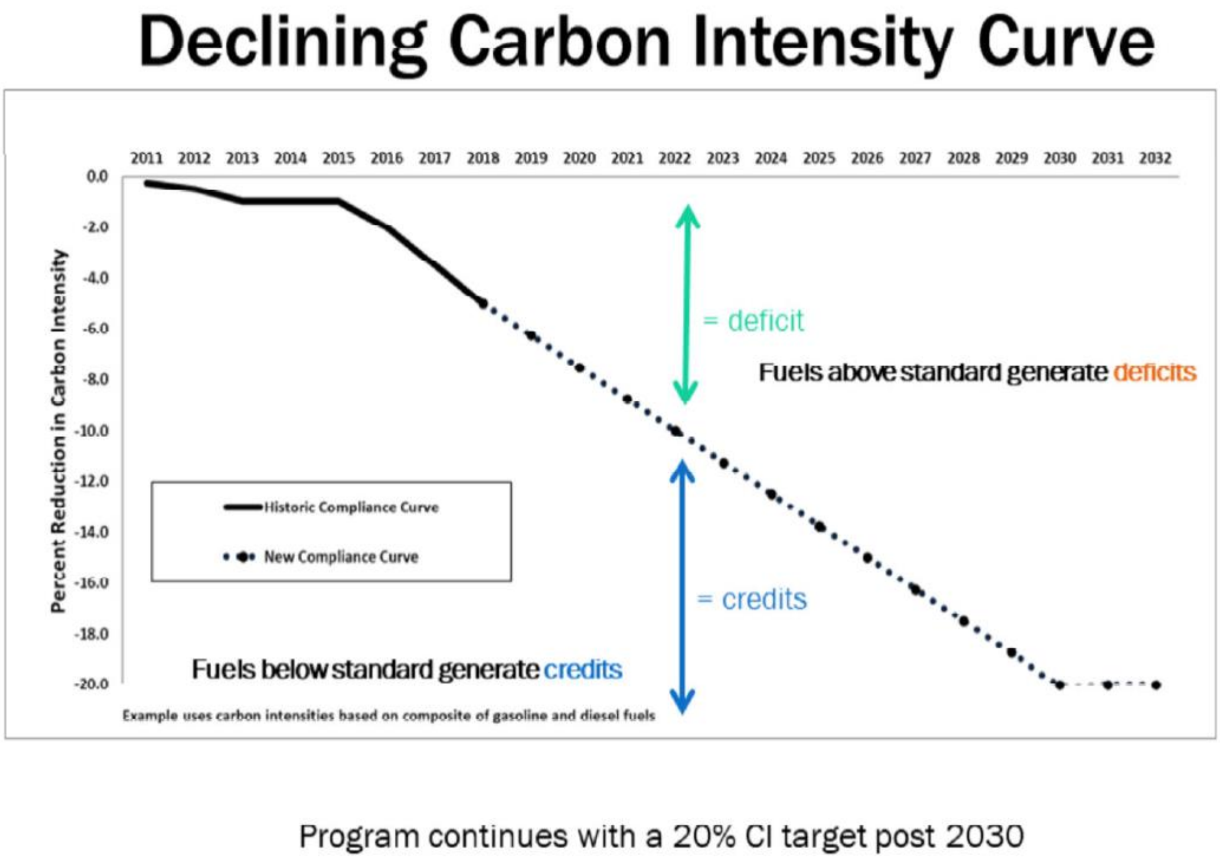
(A) A biogas control system, or digester, is used to capture biomethane from manure management on dairy cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.

(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane, and any other greenhouse gas emission reduction that otherwise would occur.

(C) The fuel pathway derived from biomethane from dairy cattle or swine manure digestion pursuant to section 95488.3(e) does not (1) contribute any amount of nitrogen oxides, volatile organic compounds, sulfur oxides, ammonia, or particulate matter with an aerodynamic diameter of ten microns or less into the ambient air; (2) cause or contribute to groundwater or surface water pollution or degradation; (3) intensify water demand in areas medium and high priority water basins; or (4) intensify or exacerbate any negative local impacts including but not limited to odor and insects.

C. APPENDIX C: TABLES AND FIGURES

Figure 1: Declining Annual Benchmark for the LCFS program.[219]



219 CAL. AIR RES. BD., *LCFS Basics* (2019), *available at* https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited Oct. 12, 2021).

Table 1. Credit Value Calculator from LCFS Data Dashboard.[220]

Credit Value Calculator:
Estimated LCFS Premium at Sample LCFS Credit Prices

Alternative Fuel Premiums at Sample LCFS Credit Prices
($/gal gasoline-equivalent for fuels used as gasoline substitutes)

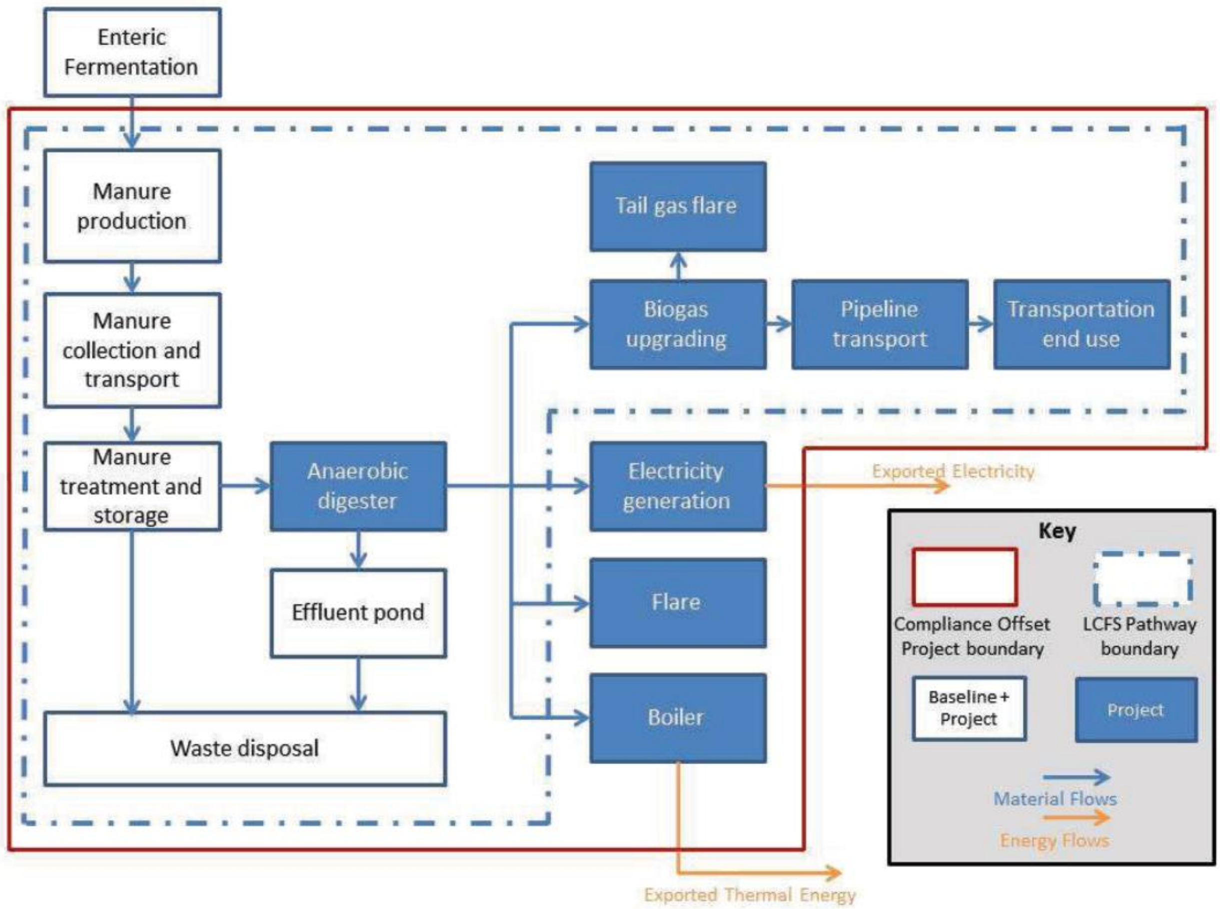
	CI Score (gCO_2e/MJ)	Credit Price $196	$80	$100	$120	$160	$200
	-273	$8.31	$3.39	$4.24	$5.09	$6.79	$8.48
	10	$1.89	$0.77	$0.96	$1.16	$1.54	$1.93
	20	$1.66	$0.68	$0.85	$1.02	$1.36	$1.70
	30	$1.44	$0.59	$0.73	$0.88	$1.17	$1.46
	40	$1.21	$0.49	$0.62	$0.74	$0.99	$1.23
	50	$0.98	$0.40	$0.50	$0.60	$0.80	$1.00
	60	$0.75	$0.31	$0.38	$0.46	$0.62	$0.77
	70	$0.53	$0.22	$0.27	$0.32	$0.43	$0.54
	80	$0.30	$0.12	$0.15	$0.18	$0.25	$0.31
	90	$0.07	$0.03	$0.04	$0.04	$0.06	$0.07
	100	-$0.15	-$0.06	-$0.08	-$0.09	-$0.13	-$0.16
	110	-$0.38	-$0.16	-$0.19	-$0.23	-$0.31	-$0.39
	120	-$0.61	-$0.25	-$0.31	-$0.37	-$0.50	-$0.62
	130	-$0.83	-$0.34	-$0.43	-$0.51	-$0.68	-$0.85
	140	-$1.06	-$0.43	-$0.54	-$0.65	-$0.87	-$1.08
	150	-$1.29	-$0.53	-$0.66	-$0.79	-$1.05	-$1.32
CaRFG* ($/gallon)	100.82	-$0.139	-$0.057	-$0.071	-$0.085	-$0.113	-$0.142

* Maximum pass-through cost for gasoline. Assumes a blend of CARBOB with 10 volume percent ethanol at a CI of 79.9 g/MJ. Ethanol at 79.9 g/MJ is assumed to receive no LCFS premium.

Last Modified 05/31/2019

[220] Data Dashboard, CAL. AIR RES. BD. Figure 7, *https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm* (last visited Oct. 20, 2021).

Figure 2. CARB schematic of the system boundaries for upgraded biogas (biomethane) from Anaerobic digestion of Dairy Manure.[221]



[221] CAL. AIR RES. BD., *supra* note 96 at 13.

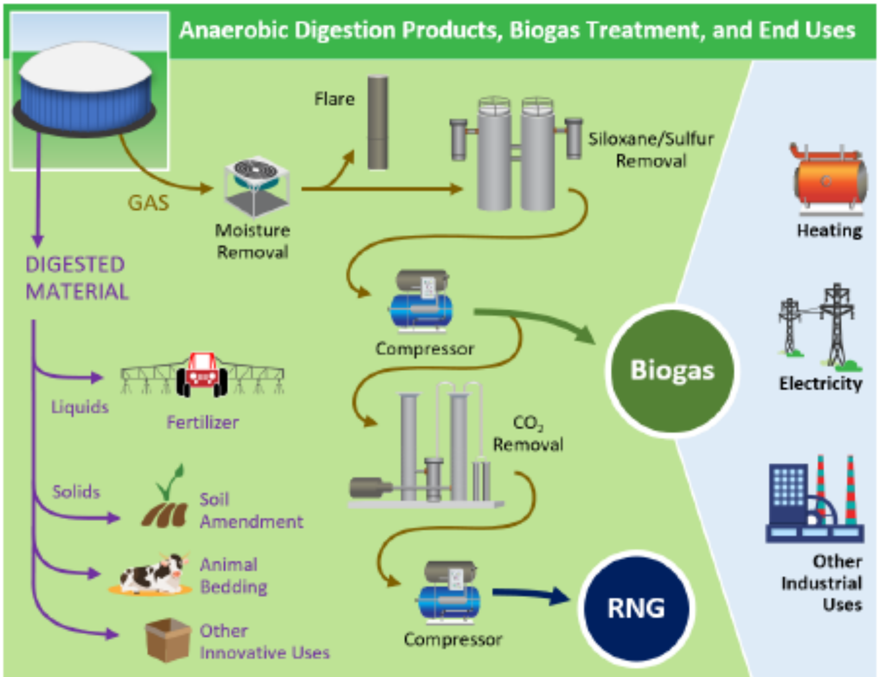
Figure 3. Waste Management Hierarchy chart for manure management.[222]

Waste Management Hierarchy	Attribute	Applicability in animal manure management
Avoidance	Most preferred option. Preventive. Use of less hazardous materials in the design and manufacture of products. Develop strategies for cleaner and environmentally friendly production	While the production of wastes cannot be completely eliminated in animal production, the production can be made cleaner and environmentally friendly
Reduction of wastes	Second most preferred option. Preventive. Actions to make changes in the type of materials being used for specific products. This approach contributes to effective savings of natural resources	Applicable
Reuse	Predominantly ameliorative and partly preventive. The waste is collected during the production phase and fed back into the production process. Reduce the amount of wastes generated and the cost of production. Desirable.	Applicable
Recycle	Predominantly ameliorative and partly preventive. The waste materials are collected and processed, and used in the production of new products. The process prevents pollution. Desirable.	Applicable
Energy recovery	Predominantly assimilative and partly ameliorative. This is also called waste to energy conversion. Wastes are converted to usable energy forms such as heat, light, electricity, etc. Desirable.	Applicable
Treatment	Predominantly assimilative and partly ameliorative. Desirable.	Applicable
Sustainable disposal	Disposal is the least preferred option in the waste management hierarchy and should be avoided.	Possible but not preferred

[222] Gabriel Adebayo Malomo et al., *Sustainable Animal Manure Management Strategies and Practices*, 9 (Aug. 29, 2018) https://www.intechopen.com/books/agricultural-waste-and-residues/sustainable-animal-manure-management-strategies-and-practices.

Figure 4. Diagram of downstream uses of digested materials.[223]

Figure 3. AD Products, Biogas Treatment and End Uses



[223] ENV'T. PROT. AGENCY, *An Overview of Renewable Natural Gas from Biogas* 4 (July 2020) https://www.epa.gov/sites/production/files/2020-07/documents/lmop_rng_document.pdf.

Figure 5. Rise in Average Monthly Credit Price since 2013.[224]

Table 2. The California dairy industry experienced negative average residuals in 2015 and 2016, indicating a lack of profit in these years.[225]

Table 1.6: California Dairy Farm Annual Unit Costs of Production by Category 2014-2017

Dairy Input	2014 $/cwt	2015 $/cwt	2016 $/cwt	2017 $/cwt
Feed	$11.05	$10.46	$9.22	$8.77
Hired Labor	$1.56	$1.70	$1.74	$1.87
Herd Replacement	$1.37	$2.12	$2.10	$1.88
Operating Costs	$2.88	$2.93	$2.92	$3.06
Milk Marketing	$0.56	$0.56	$0.55	$0.55
Total Costs	**$17.42**	**$17.77**	**$16.53**	**$16.13**
Average Mailbox Price	**$22.37**	**$15.94**	**$15.56**	**$16.99**
Price – Costs (Residual)	**$4.95**	**-$1.83**	**-$0.97**	**$0.86**

Source: CDFA California Dairy Cost of Production Annuals
https://www.cdfa.ca.gov/dairy/dairycop_annual.html

[224] AcMoody, *supra* note 128 at 4.
[225] Matthews, *supra* note 130 at 20.

Figure 6. Groundwater contamination sites in Kern County.[226]

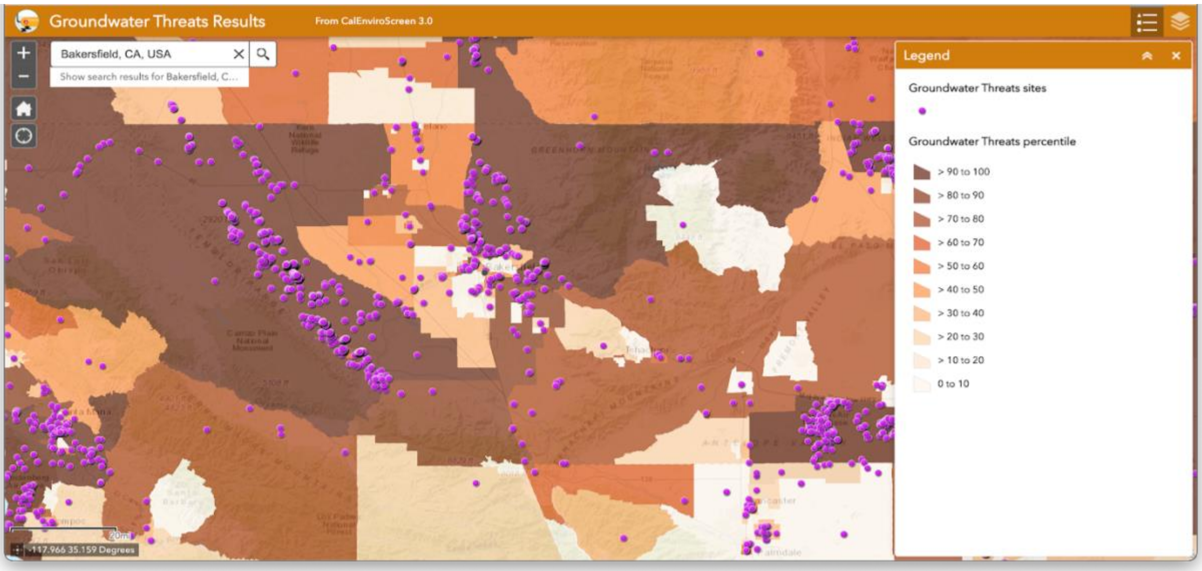
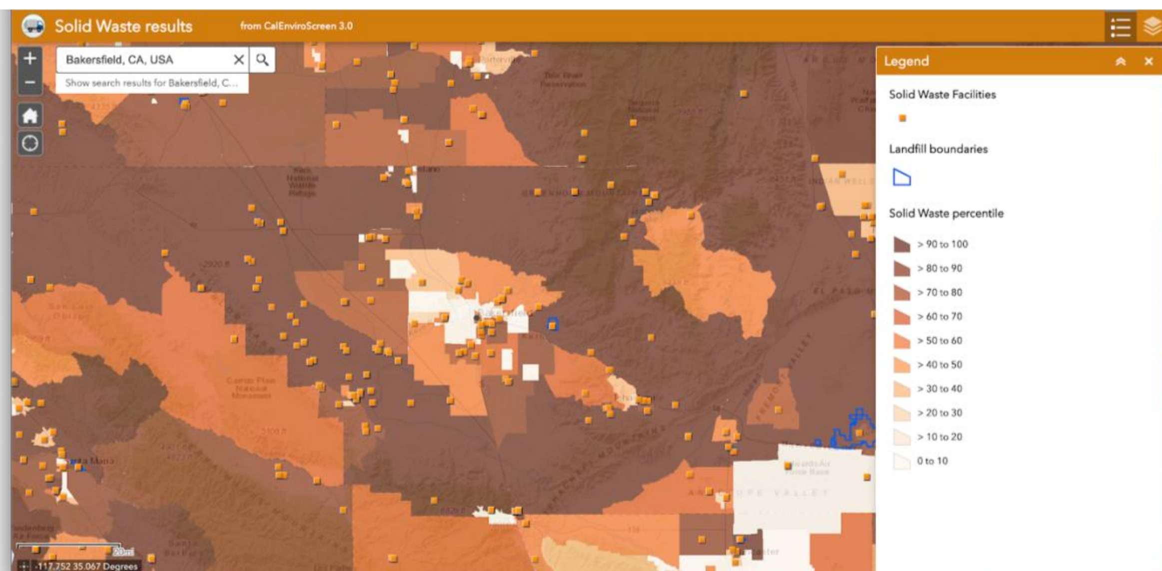
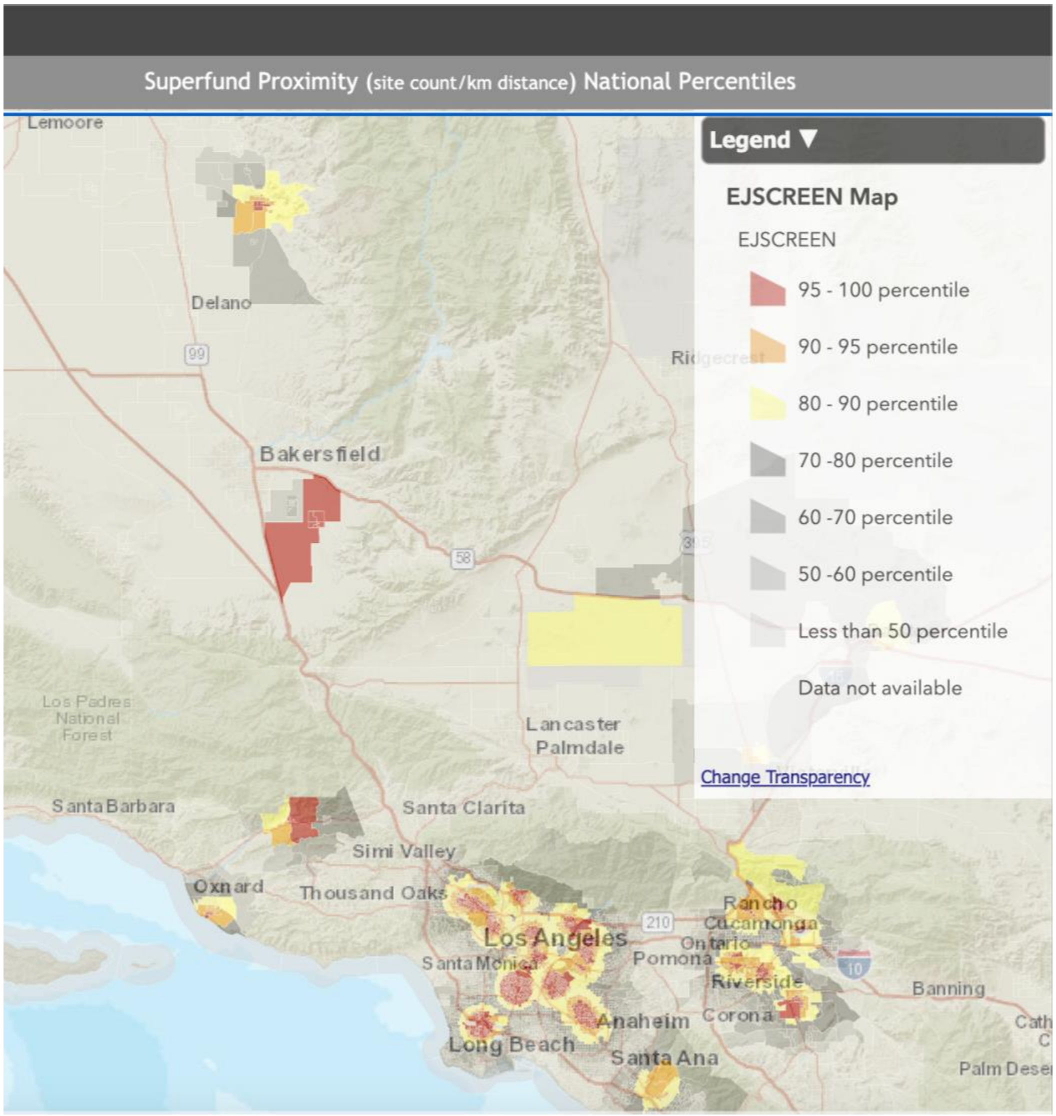


Figure 7. Solid waste contamination in Kern County.[227]



[226] CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, *supra* note 29.
[227] *Id.*

Figure 8. Superfund site near Bakersfield, CA.[228]



[228]*EJScreen*, ENV'T. PROT. AGENCY, https://www.epa.gov/ejscreen (last accessed Apr. 10, 2021).

Table 3. A list of the top counties that sell cow's milk ($ billions), the majority of which are in California.[229]

Top Counties in Cow's Milk Sales ($ billions)	
Tulare, CA	1.8
Merced, CA	1.1
Gooding, ID	0.7
Stanislaus, CA	0.7
Kings, CA	0.6
Kern, CA	0.5
Yakima, WA	0.4
Lancaster, PA	0.4
Fresno, CA	0.4
San Joaquin, CA	0.4

Does not include counties withheld to avoid disclosing individual data.

[229] U.S. DEP'T OF AGRIC., *Dairy Cattle and Milk Production* at 2 (Oct. 2014) https://www.nass.usda.gov/Publications/Highlights/2014/Dairy_Cattle_and_Milk_Production_Highlights.pdf.

Table 4. Demographic data on Kern, Kings, Madera, and San Joaquin Counties.[230]

Fact	Kern County, California	Kings County, California	Madera County, California	San Joaquin County, California
Population estimates, July 1, 2019, (V2019)	900,202	152,940	157,327	762,148
Population estimates base, April 1, 2010, (V2019)	839,621	152,974	150,834	685,306
Population, percent change - April 1, 2010 (estimates base) to	7.20%	0.00%	4.30%	11.20%
Population, Census, April 1, 2010	839,631	152,982	150,865	685,306
Persons under 5 years, percent	7.60%	7.60%	7.30%	6.90%
Persons under 18 years, percent	28.80%	27.00%	27.40%	26.80%
Persons 65 years and over,	11.20%	10.50%	14.30%	13.10%
Female persons, percent	48.80%	44.90%	51.80%	50.10%
White alone, percent	82.30%	80.80%	85.90%	66.10%
Black or African American alone,	6.30%	7.50%	4.20%	8.30%
American Indian and Alaska Native alone, percent	2.60%	3.20%	4.40%	2.00%
Asian alone, percent	5.40%	4.40%	2.60%	17.40%
Native Hawaiian and Other Pacific Islander alone, percent	0.30%	0.40%	0.30%	0.80%
Two or More Races, percent	3.20%	3.70%	2.60%	5.50%
Hispanic or Latino, percent	54.60%	55.30%	58.80%	42.00%
White alone, not Hispanic or Latino, percent	32.80%	31.30%	33.20%	30.50%
Veterans, 2015-2019	35,594	9,684	6,317	29,013
Foreign born persons, percent,	19.90%	18.90%	20.20%	23.30%
Housing units, July 1, 2019,	302,898	46,965	51,438	248,636
Owner-occupied housing unit rate, 2015-2019	58.30%	52.30%	64.10%	56.60%
Median value of owner-occupied housing units, 2015-2019	213,900	215,900	251,200	342,100
Median selected monthly owner costs -with a mortgage, 2015-2019	$1,527	$1,459	$1,551	$1,907
Median selected monthly owner costs -without a mortgage, 2015-	$452	$446	$478	$523
Median gross rent, 2015-2019	$978	$990	$1,014	$1,208
Building permits, 2019	2,261	409	644	3,499
Households, 2015-2019	270,282	43,452	44,881	228,567
Persons per household, 2015-	3.17	3.13	3.28	3.17
Living in same house 1 year ago, percent of persons age 1 year+,	86.10%	81.90%	87.90%	86.80%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	44.20%	41.50%	45.30%	40.90%
High school graduate or higher, percent of persons age 25 years+,	74.10%	73.40%	71.90%	79.30%
Bachelor's degree or higher, percent of persons age 25 years+,	16.40%	14.70%	14.60%	18.80%
With a disability, under age 65 years, percent, 2015-2019	7.80%	8.60%	8.70%	8.70%
Persons without health insurance, under age 65 years,	9.00%	8.50%	10.70%	7.80%
In civilian labor force, total, percent of population age 16	58.00%	51.80%	54.30%	60.30%
In civilian labor force, female, percent of population age 16	52.40%	51.50%	47.90%	53.60%
Total accommodation and food services sales, 2012 ($1,000)	1,092,151	378,595	150,065	808,606
Total health care and social assistance receipts/revenue,	3,675,000	587,818	760,956	3,447,722
Median household income (in 2019 dollars), 2015-2019	$53,350.00	$57,848.00	$57,585.00	$64,432.00
Per capita income in past 12 months (in 2019 dollars), 2015-	$23,326.00	$22,373.00	$22,853.00	$27,521.00
Persons in poverty, percent	19.00%	16.00%	17.60%	13.60%

230 *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/US/PST045219 (last visited Apr. 10, 2021).

Table 5. Demographic data on Merced, Tulare, Fresno, and Stanislaus Counties.[231]

Fact	Merced County, California	Tulare County, California	Fresno County, California	Stanislaus County, California
Population estimates, July 1, 2019, (V2019)	277,680	466,195	999,101	550,660
Population estimates base, April 1, 2010, (V2019)	255,796	442,182	930,507	514,450
Population, percent change - April 1, 2010 (estimates base) to July 1, 2019, (V2019)	8.60%	5.40%	7.40%	7.00%
Population, Census, April 1, 2010	255,793	442,179	930,450	514,453
Persons under 5 years, percent	7.70%	7.80%	7.60%	7.10%
Persons under 18 years, percent	29.30%	30.50%	28.20%	27.00%
Persons 65 years and over, percent	11.40%	11.60%	12.60%	13.40%
Female persons, percent	49.50%	50.00%	50.10%	50.40%
White alone, percent	82.20%	88.20%	76.60%	83.30%
Black or African American alone, percent	3.90%	2.20%	5.80%	3.50%
American Indian and Alaska Native alone, percent	2.50%	2.80%	3.00%	2.00%
Asian alone, percent	7.80%	4.00%	11.10%	6.10%
Native Hawaiian and Other Pacific Islander alone, percent	0.40%	0.20%	0.30%	0.90%
Two or More Races, percent	3.20%	2.70%	3.20%	4.20%
Hispanic or Latino, percent	61.00%	65.60%	53.80%	47.60%
White alone, not Hispanic or Latino, percent	26.50%	27.70%	28.60%	40.40%
Veterans, 2015-2019	9,225	14,633	36,125	21,051
Foreign born persons, percent, 2015-2019	26.30%	21.80%	21.20%	20.30%
Housing units, July 1, 2019, (V2019)	86388	151603	336473	182978
Owner-occupied housing unit rate, 2015-2019	52.20%	57.10%	53.30%	57.80%
Median value of owner-occupied housing units, 2015-2019	252,700	205,000	255,000	291,600
Median selected monthly owner costs -with a mortgage, 2015-2019	1,493	1,420	1,631	1,702
Median selected monthly owner costs -without a mortgage, 2015-2019	$460.00	$421.00	$484.00	$503.00
Median gross rent, 2015-2019	$1,021.00	$942.00	$998.00	$1,155.00
Building permits, 2019	948	1,872	3,393	699
Households, 2015-2019	80,008	138,238	307,906	173,898
Persons per household, 2015-2019	3.32	3.3	3.14	3.09
Living in same house 1 year ago, percent of persons age 1 year+, 2015-2019	86.60%	88.60%	85.80%	87.90%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	53.30%	51.30%	44.60%	42.90%
High school graduate or higher, percent of persons age 25 years+, 2015-2019	69.10%	70.80%	76.00%	78.90%
Bachelor's degree or higher, percent of persons age 25 years+, 2015-2019	13.80%	14.60%	21.20%	17.10%
With a disability, under age 65 years, percent, 2015-2019	9.10%	8.20%	9.20%	9.00%
Persons without health insurance, under age 65 years, percent	9.00%	9.00%	8.80%	7.10%
In civilian labor force, total, percent of population age 16 years+, 2015-2019	59.60%	59.00%	60.90%	60.90%
In civilian labor force, female, percent of population age 16 years+, 2015-2019	51.00%	51.10%	55.20%	53.40%
Total accommodation and food services sales, 2012 ($1,000)	232,910	451,880	1,226,169	705,698
Total health care and social assistance receipts/revenue, 2012 ($1,000)	788114	1610236	5325615	3634960
Median household income (in 2019 dollars), 2015-2019	$53,672.00	$49,687.00	$53,969.00	$60,704.00
Per capita income in past 12 months (in 2019 dollars), 2015-2019	$23,011.00	$21,380.00	$24,422.00	$26,258.00
Persons in poverty, percent	17.00%	18.90%	20.50%	13.00%

[231] *Id.*

Table 6. Quick facts on potential pathogens found in digestate and links for further information.[232]

Pathogen	**Effects**	**For more information**
Cryptosporidium parvum	"[M]icroscopic parasite that causes the diarrheal disease cryptosporidiosis."	https://www.cdc.gov/parasites/crypto/index.html
Salmonella spp	"Most people with Salmonella infection have diarrhea, fever, and stomach cramps."	https://www.cdc.gov/salmonella/general/index.html
norovirus	"Norovirus is a very contagious virus that causes vomiting and diarrhea."	https://www.cdc.gov/norovirus/index.html
Streptococcus pyogenes	"[C]an cause both noninvasive and invasive disease, as well as nonsuppurative sequelae. "	https://www.cdc.gov/groupastrep/diseases-hcp/index.html
E. coli enteropathogenic (EPEC)	"[A]re gram-negative bacteria that inhabit the gastrointestinal tract. Most strains do not cause illness. Pathogenic E. coli are categorized into pathotypes on the basis of their virulence genes. Six pathotypes are associated with diarrhea	https://wwwnc.cdc.gov/travel/yellowbook/2020/travel-related-infectious-diseases/escherichia-coli-diarrheagenic

232 *Parasites – Cryptosporidium (also known as "Crypto")*, CDC, https://www.cdc.gov/parasites/crypto/index.html (last updated July 1, 2019); *Salmonella*, CDC, https://www.cdc.gov/salmonella/general/index.html (last updated Dec 5, 2019); *Norovirus*, CDC, https://www.cdc.gov/norovirus/index.html (last updated Mar. 5, 2021); *Group A Streptococcal (GAS) Disease*, CDC, https://www.cdc.gov/groupastrep/diseases-hcp/index.html (last updated May 7, 2020); Alison Winstead et al., *Escherichia coli, Diarrheagenic*, CDC, https://wwwnc.cdc.gov/travel/yellowbook/2020/travel-related-infectious-diseases/escherichia-coli-diarrheagenic (last updated July 1, 2021); J. L. Cloud et al., *Identification of Mycobacterium spp. by Using a Commercial 16S Ribosomal DNA Sequencing Kit and Additional Sequencing Libraries*, 40(2) J. Clinical Microbiology 400, 400 (Feb. 2002); *Typhoid Fever and Paratyphoid Fever*, CDC, https://www.cdc.gov/typhoid-fever/index.html (last updated Aug. 22, 2018); *Fact Sheet: Clostridium spp*, WickhamLaboratories, https://wickhamlabs.co.uk/technical-resource-centre/fact-sheet-clostridium-spp/ (last visited May 5, 2021); Listeria (Listeriosis), CDC, https://www.cdc.gov/listeria/symptoms.html (Dec. 12, 2016).

	(diarrheagenic) […] enteropathogenic E. coli (EPEC)”	
Mycobacterium spp.	"Mycobacterium species are a group of acid-fast, aerobic, slow-growing bacteria. The genus comprises more than 70 different species, of which about 30 have been associated with human disease (23)."	https://www.ncbi.nlm.nih.gov/pmc/articles/PMC153382/#:~:text=Mycobacterium%20species%20are%20a%20group,the%20causative%20agent%20of%20tuberculosis
Salmonella typhi (followed by S. paratyphi)	"Typhoid fever and paratyphoid fever are life-threatening illnesses caused by Salmonella serotype Typhi and Salmonella serotype Paratyphi, respectively."	https://www.cdc.gov/typhoid-fever/index.html
Clostridium spp.	“Clostridia are one of the most commonly studied anaerobes that cause disease in humans”. Some of the species of Clostridium can cause: botulism, overgrow in the intestine compromising the inherent gut flora (potentially leading to colitis), tetanus, gas gangrene (myonecrosis), and toxic shock syndrome.	https://wickhamlabs.co.uk/technical-resource-centre/fact-sheet-clostridium-spp/
Listeria monocytogenes	"[C]an cause fever and diarrhea similar to other foodborne germs, but this type of Listeria infection is rarely diagnosed. Symptoms in people with invasive listeriosis, meaning the bacteria has spread beyond the gut, depend on whether the person is pregnant."	https://www.cdc.gov/listeria/symptoms.html

Exhibit B: Petition for Reconsideration

BEFORE THE CALIFORNIA AIR RESOURCES BOARD

PETITION FOR RECONSIDERATION OF THE DENIAL OF THE PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM

TABLE OF CONTENTS

I. BACKGROUND

On October 27, 2021, the Association of Irritated Residents, Leadership Counsel for Justice & Accountability, Food & Water Watch, and the Animal Legal Defense Fund ("Petitioners") filed a petition for rulemaking[1] ("Petition") with the California Air Resources Board (CARB) pursuant to Government Code section 11340.6.[2] The Petition asked CARB to amend the Low Carbon Fuel Standard (LCFS) to exclude all fuels derived from factory farm gas or, in the alternative, to reform the LCFS to account for the full life cycle of factory farm gas emissions—including all upstream and downstream emissions from activities and inputs at dairy and pig facilities—and exclude non-additional emission reductions that occur as a result of other methane reduction programs. As explained in more detail below, the Petition also highlighted LCFS transparency issues and that the LCFS has disproportionate adverse and cumulative impacts on low-income and Latina/o/e/ communities.

On November 29, 2021, Petitioners and CARB entered into a Tolling Agreement[3] providing that CARB would have until January 28, 2022, to respond to the Petition—an additional sixty days on top of the thirty days provided by statute.[4] In consideration of this extension, CARB agreed to "engage in good faith discussions" with Petitioners in the intervening months "in an effort to reach common ground with respect to the issues raised in the Petition."[5]

To effectuate the Tolling Agreement, Petitioners met with CARB members and staff, including the Executive Officer, numerous times. During the meetings, the parties discussed the issues raised in the Petition and asked CARB to grant interim relief by suspending pathway certifications for factory farm gas pending the rulemaking. Petitioners also requested this interim

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[1] Attach. 1, ASSOCIATION OF IRRITATED RESIDENTS ET AL., PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM (Oct. 27, 2021).

[2] The petition followed two years of Petitioners' comments in opposition to certifications of pathways for factory farm gas. To date, one or more of the petitioning organizations have submitted comments in opposition to thirty-three Tier 2 applications for pathways for factory farm gas—and CARB has certified all of them over Petitioners' objections. *LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/resources/documents/lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (applications B0215, B0216, B0217, B0280); *2021 LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/2021-lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (applications B0218, B0242, B0207, B0220, B0214, B0198, B0185, B0175, B0197, B0173, B0166, B0163, B0148); *2020 LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/resources/documents/2020-lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (applications B0127, B0096, B0097, B0109, B0108, B0072, B0098, B0059, B0089); *2019 LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/resources/documents/2019-lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (applications B0019, B0010, B0060, B0058, B0037, B0038, B0019). Many of the petitioning organizations also submitted comments in opposition to a new temporary pathway for factory farm gas, which it appears CARB never certified. *See 2020 LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/resources/documents/2020-lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (notice documentation and comments); *LCFS Life Cycle Analysis Models and Documentation*, CARB, https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation (last visited Mar. 15, 2022) (not listing the proposed temporary pathway as certified).

[3] Attach. 2, TOLLING AGREEMENT (Nov. 29, 2021).

[4] Cal. Gov't Code § 11340.7(a).

[5] Tolling Agreement, *supra* note 3, at 1.

relief in comments in opposition to several proposed pathway certifications[6] and in comments on the LCFS workshop that took place on January 7, 2022.[7]

On January 26, 2022—two days ahead of the deadline in the Tolling Agreement and one day before a previously scheduled Board[8] meeting—the Executive Officer responded to the Petition ("Response"), granting it in part and denying it in part.[9] The Response denied the Petition "by declining to amend the LCFS regulation at this time in the manners suggested."[10] The Response purported to grant other relief "by affirming that CARB will continue to engage with petitioners on the programmatic and environmental justice and environmental integrity concerns raised in the petition through the ongoing AB 32 Climate Change Scoping Plan update process and upcoming informal workshops on LCFS throughout 2022, both of which will inform any future LCFS amendments."[11] The Executive Officer relied on two justifications for the Response. First, the Response declined near-term amendments because "it is premature to consider amending the LCFS regulation until the Scoping Plan update process" has been completed.[12] Second, the Response claimed that Senate Bill 1383 (SB 1383) "directs CARB to 'ensure' LCFS crediting for methane reductions" and thus CARB lacked authority to grant the relief sought by the Petition.[13]

CARB also denied Petitioners' request for interim relief on January 26, 2022.[14] Specifically, CARB explained that a petition for rulemaking "is not a proper legal mechanism to stop implementing the current version of the LCFS regulation."[15] CARB has continued certifying all pathways for factory farm gas presented to the agency—despite Petitioners' comments in opposition to such pathways[16] and notwithstanding concerns raised by Board members, as described below.

The next day, on January 27, 2022, Petitioners commented at the Board meeting and raised their concerns about the Response and the issues raised in the Petition. Several Board

[6] *LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/resources/documents/lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (showing Petitioners' comments in opposition to application B0280 while the Petition was pending); *2021 LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/2021-lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (showing Petitioners' comments in opposition to applications B0218, B0242, B0207, and B0220 while the Petition was pending).
[7] Attach. 3, Coalition Comments on the Public Workshop Re: Potential Future Changes to the LCFS Program (Jan. 7, 2022), https://www.arb.ca.gov/lists/com-attach/108-lcfs-wkshp-dec21-ws-ADIHMV1uB2YBKVRk.pdf.
[8] "Board" refers to the members of the Board, rather CARB as an agency.
[9] Attach. 4, CAL. AIR RES. BD., RESPONSE TO PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM (Jan. 26, 2022).
[10] *Id.* at 7.
[11] *Id.*
[12] *Id.* at 4.
[13] *Id.* at 5 (quoting Cal. Health & Safety Code § 39730.7(e)).
[14] Attach. 5, CARB Letter to Petitioners Re: Requests to Deny or Delay Consideration of Low Carbon Fuel Standard (LCFS) Pathway Certifications (Jan. 26, 2022).
[15] *Id.*
[16] *2021 LCFS Pathways Requiring Public Comments*, CARB, https://ww2.arb.ca.gov/2021-lcfs-pathways-requiring-public-comments (last visited Mar. 25, 2022) (showing CARB certified applications B0218, B0242, B0207, and B0220 over Petitioners' comments in opposition while the Petition was pending).

members likewise raised concerns. Accordingly, the Board directed the Executive Officer to set a public workshop specifically on the issues raised in the Petition and share the findings and discussion at the workshop with the Board at a future Board meeting to "allow the Board to hear about the issues in more detail and provide guidance in terms of moving forward with a rulemaking process."[17]

> CHAIR RANDOLPH: All right. Thank you. That was a good discussion. All right. So I think the -- several Board members have raised kind of the same sort of concerns, intentions around recognizing that the dairy participation in LCFS is an important issue, is dairies do affect communities, but also recognizing that there's a lot of issues around that. There's a lot of factual issues, there's policy issues, and there's also kind of a learning curve that I think we want to make sure that all Board members have an opportunity to participate in with regard to LCFS generally and with regard to this issue specifically.
>
> So my suggestion to Executive Officer Corey is, recognizing the heavy lift that we're doing with the Scoping Plan and with the 23 Board meetings this year, and also recognizing that there -- you know, we have received this petition, but there hasn't been any sort of public process or discussion about that, my suggestion is that there be a -- and this kind of dovetails nicely with Exec -- the Executive Officer's concerns about making sure there's a robust opportunity for information sharing and engagement. *My suggestion is that we do a public workshop specifically on this issue*, ideally within the next few months, and then come back to the Board with an item after that public workshop, and -- where staff could share the findings and the discussion and really kind of allow the Board to hear about the issues in more detail and provide guidance in terms of moving forward with a rulemaking process.
>
> And so that would help kind of get some of the groundwork that we need to do before the formal process happening sooner rather than later with a recognition that opening the full formal process is going to be a big undertaking that's going to take a bit more time. I would like to get the -- Mr. Corey's thoughts on that.
>
> EXECUTIVE OFFICER COREY: Yes. Thanks, Chair and Board members for the discussion -- really thoughtful discussion. And to your suggestion, Chair, absolutely, I think that's on point within the next few months. We'll get going on the full conversation that -- including petitioners and others in a workshop setting that I think

[17] CAL. AIR RES. BD., VIDEOCONFERENCE MEETING, STATE OF CALIFORNIA, AIR RESOURCES BOARD, ZOOM PLATFORM 171–73 (Jan. 27, 2022), https://ww2.arb.ca.gov/sites/default/files/barcu/board/mt/2022/mt012722.pdf (transcript).

> will help and be part honestly a pre-rulemaking, because it will pull additional information together. So we'll develop a schedule over the next few months that would include the workshop that you just -- a public workshop that you just referred to as well as report back to the Board, how did the workshop go, what are the learnings, what's the process going forward. So we'll get going on that.[18]

II. THE PETITION

The Petition asked CARB to amend LCFS to exclude all fuels derived from factory farm gas or, in the alternative, to reform the LCFS to account for the full life cycle of factory farm gas emissions—including all upstream and downstream emissions from activities and inputs at dairy and pig facilities—and exclude non-additional emission reductions that occur as a result of other factory farm gas incentives. The Petition provides three main reasons why CARB must grant this relief. First, factory farm gas pathways fail to achieve the maximum technologically feasible and cost-effective emissions reductions, as Assembly Bill 32 (AB 32) requires, because they fail to incorporate proper lifecycle analyses (LCAs), leading to inflated credit values. Second, the LCFS fails to ensure that credited emission reductions are additional to reductions that would have otherwise occurred as required by section 38562(d)(2) of the Health & Safety Code. The resulting combination of inflated credit values and credits for non-additional reductions incentivize increased manure generation, industry consolidation, and facility expansions that exacerbate localized pollution and disparate impacts. Thus, CARB fails to achieve the maximum technologically feasible and cost-effective greenhouse gas (GHG) emissions.[19] Third, factory farm gas pathways fail to maximize additional environmental benefits and interfere with efforts to improve air quality.[20]

The Petition also asked CARB to evaluate and amend the LCFS to remedy its disproportionate adverse and cumulative impacts on low-income and Latina/o/e/ communities in violation of state and federal law.[21] The Petition provides three main reasons why CARB must grant this relief. First, LCFS credits and the subsequent trading of those credits incentivize activities that result in public health and environmental harms in disproportionately low-income and Latina/o/e communities, particularly in the San Joaquin Valley.[22] Second, CARB must ensure that the LCFS complies with CA 11135, CA 12955, and Title VI of the Civil Rights Act of 1964 to prevent discrimination.[23] Third, CARB failed to design the LCFS in a manner that is equitable, and CARB fails on an ongoing basis to consider the social costs of GHG emissions and to ensure that the LCFS does not disproportionately impact low-income communities.[24]

Finally, the Petition asked CARB to address the lack of transparency as to pathways for factory farm gas.[25] Specifically, there is no way for the public to access trading data to determine

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[18] *Id.* (emphasis added).
[19] Petition, *supra* note 1, at 10–26.
[20] *Id.* at 26–31.
[21] *Id.* at 31–36.
[22] *Id.* at 31–34.
[23] *Id.* at 34–35.
[24] *Id.* at 35–36.
[25] *Id.* at 36–37.

the location of facilities purchasing LCFS factory farm credits, and what records are available are heavily redacted.[26] This makes it difficult to determine potential disparate impacts.[27]

III. CARB SHOULD RECONSIDER AND GRANT THE PETITION.

CARB has the authority—and the duty—to grant the Petition.[28] CARB may not deny the Petition and defer consideration of the issues for three primary reasons. First, the Response neither disputes nor responds to the evidence demonstrating that factory farm gas in the LCFS violates applicable law and undermines AB 32's purpose and goals by (1) grossly minimizing carbon intensity (CI), which inflates factory farm gas credit values; (2) perversely incentivizing the entrenchment, expansion, and consolidation of factory farms and methane-generating liquified manure management systems; (3) authorizing non-additional emission reductions achieved by other programs and credited to those programs, including the Dairy Digester Research and Development Program, the SB 1383 methane reduction mandate, and the Aliso Canyon Mitigation Agreement; and (4) causing adverse and disparate environmental impacts.

Second, SB 1383 does not justify denial of the Petition when it mandates neither the inclusion nor the overvaluation of factory farm gas in the LCFS.

Finally, San Joaquin Valley communities cannot wait until 2023 or later for CARB to address the issues raised in the Petition, which disproportionately harm them.

A. CARB has neither disputed nor responded to evidence that including factory farm gas in the LCFS violates applicable law and undermines the purpose and goals of AB 32.

CARB has not responded to the substantive issues presented in the Petition—and these issues are both urgent and significant. CARB's decision to include and overvalue factory farm gas in the LCFS violates AB 32 and completely undermines its purpose and goals by causing an *increase* in pollution, especially in San Joaquin Valley communities and in communities where CARB admits that transportation fuels have racially disparate impacts.[29] CARB must begin rulemaking immediately to address these issues, as the damage intensifies and compounds with each passing day that CARB allows the LCFS to continue unreformed.

1. Factory farm gas credits distort and undermine the LCFS.

The Petition explains that CARB's current administration of the LCFS violates AB 32 and the LCFS by artificially minimizing the CI of factory farm gas, which drastically inflates the

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[26] *Id.*
[27] *Id.*
[28] *See* Cal. Gov't Code § 11340.7(c) ("Any interested person may request a reconsideration of any part or all of a decision of any agency on any petition submitted. The request shall be submitted in accordance with Section 11340.6 and include the reason or reasons why an agency should reconsider its previous decision no later than 60 days after the date of the decision involved.").
[29] *See* CAL. AIR RES. BD., 2020 MOBILE SOURCE STATEWIDE STRATEGY 25–28 (Oct. 28, 2021), https://ww2.arb.ca.gov/sites/default/files/2021-12/2020_Mobile_Source_Strategy.pdf.

value of credits for factory farm gas. AB 32 mandates that CARB "shall rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required"[30] and that "any regulation adopted by [CARB] shall ensure [GHG] emission reductions achieved are real."[31] Accordingly, the LCFS requires all pathway application LCAs to include upstream and downstream GHG emissions, including direct and indirect GHG emissions from producing the feedstock—manure.[32] This "well to wheels" LCA determines the CI of the fuel, which quantifies emission reductions and determines the quantity of GHG emissions it purportedly can "offset," which in turn determines how much value those credits hold.[33]

But CARB's LCA minimizes factory farm gas CI by treating manure as a waste and factory farm gas as avoided methane emissions. CARB excludes emissions upstream and downstream in a narrow system boundary that treats the manure lagoon as the baseline—as if the lagoon occurs naturally, rather than as the result of the industry's deliberate choice to manage manure anaerobically in giant lagoons. As the Petition notes, alternative manure management techniques are available, including solid-liquid separation, scrape and vacuum collection, composting, and pasture-based practices, and evidence shows that these techniques may offer more cost-effective methane emission reductions than anaerobic digestion and may deliver additional environmental and health benefits, like reduced impact on water quality.[34]

CARB's LCA reflects an unscientific policy decision inconsistent with the reality that the industry creates manure methane intentionally and considers manure to be valuable fertilizer. As depicted below,[35] CARB's interpretation artificially minimizes the CI of fuels derived from manure methane, which artificially inflates the value of credits for those fuels, which results in a windfall to the animal agriculture and natural gas industries. But those are not the only industries that benefit—regulated entities (e.g., oil companies) holding deficits in the LCFS can keep emitting vast quantities of pollution under the guise that some those emissions are offset by factory farm gas credits purchased on the LCFS market.

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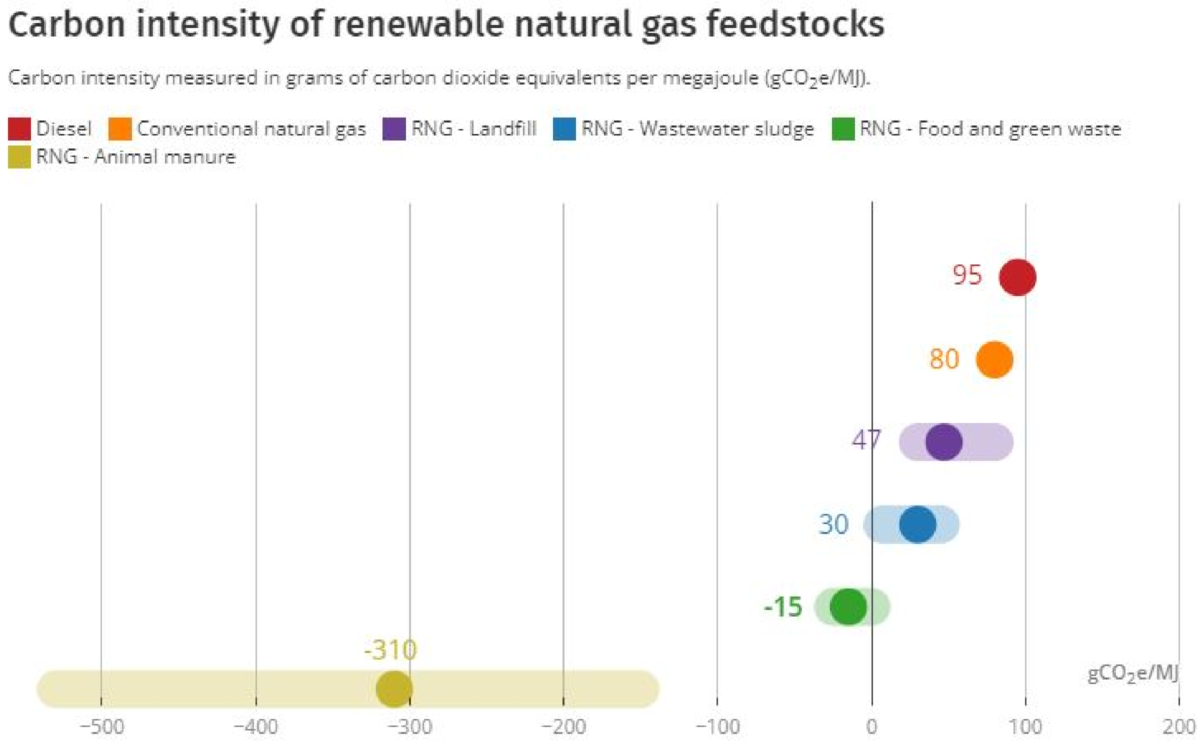
[30] Cal. Health & Safety Code § 38562(e).
[31] § 38562(d)(1) (cleaned up).
[32] Cal. Code Regs. tit. 17, §§ 95488.7(a)(2)(B); 95488.7(a)(2)(A)(2); CAL. AIR RES. BD., LOW CARBON FUEL STANDARD BASICS 16, https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited Mar. 25, 2022).
[33] *Low Carbon Fuel Standard*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Mar. 25, 2022).
[34] Petition, *supra* note 1, at 16.
[35] Emily Chung, *Renewable natural gas could help slow climate change, but by how much?*, CBC NEWS (Feb. 13, 2022), https://www.cbc.ca/news/science/renewable-natural-gas-1.6346783 (based on raw data from CARB).



CARB effectuates this policy decision beginning with the Compliance Offset Protocol – Livestock Projects ("Livestock Protocol").[36] The Livestock Protocol was created for California's Cap & Trade scheme and is not mentioned in the LCFS, but CARB adopted some of its pieces for the LCFS.[37] One piece CARB adopted is the system boundary, which designates which parts of the factory farm gas production process will be considered in calculating the CI of fuels derived from that factory farm gas.[38] This system boundary is the primary reason that the value of credits for factory farm gas are inflated—it excludes numerous relevant emissions, including those related to producing and transporting the feed that the cows eat, enteric emissions from the cows, and emissions of nitrous oxide that result from digestate composting and land application.[39]

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[36] CAL. AIR RES. BD., COMPLIANCE OFFSET PROTOCOL LIVESTOCK PROJECTS, CAPTURING AND DESTROYING METHANE FROM MANURE MANAGEMENT SYSTEMS (Nov. 14, 2014), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2014/Capandtrade14/ctlivestockprotocol.pdf. CARB incorporates this system boundary from the Livestock Protocol into CA-GREET3.0 and the Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure, a version of CA-GREET3.0 specifically for fuels derived from factory farm gas. Both CA-GREET3.0 and the Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure are incorporated into the LCFS by reference. Petitioners note that guidance documents are not incorporated by reference, including Guidance 19-06, which is specific to determining the CI of factory farm gas to electricity pathways.

[37] CAL. AIR RES. BD., LOW CARBON FUEL STANDARD, FREQUENTLY ASKED QUESTIONS, CREDIT GENERATION FOR REDUCTION OF METHANE EMISSIONS FROM MANURE MANAGEMENT OPERATIONS (Sep. 16, 2020), https://ww2.arb.ca.gov/sites/default/files/2020-09/2020_dairy-swine-manure_crediting_faq.pdf.

[38] *Id.*; *see* Livestock Protocol, *supra* note 36, at 13–17 (offset project boundary).

[39] Livestock Protocol, *supra* note 36, at 15–17; Low Carbon Fuel Standard, Frequently Asked Questions, *supra* note 37, at 4–6.

The LCFS policy decision has the consequence of undermining the goals and purpose of AB 32 by increasing emissions. As mentioned in the Petition,[40] a recent study found that increased nitrous oxide emissions associated with composting digestate solids—which are the direct result of the ways in which digestion changes the chemical composition of manure—are enough to completely cancel out captured methane emissions.[41] But CARB excludes those emissions and emissions upstream of the lagoon to generate lucrative credits that distort the market and undermine the LCFS. The Union of Concerned Scientists also questions CARB's policy, noting in comments to CARB that:

> [T]he extremely large negative [CI] values for manure biomethane are the result of several assumptions and judgements made by CARB in the [LCA] that bear reconsideration. In particular, CARB should revisit the assumption that the methane from manure lagoons is purely a waste product with no value that would be emitted into the atmosphere absent the LCCFS support for use as a transportation fuel. . . . There are any number of alternative [LCAs] that may be appropriate in the development of the CI score, for example treating biomethane as a coproduct rather than a waste. . . . It may be appropriate to set a floor of zero on the CI scores for fuels absent compelling documentation of permanent carbon sequestration. . . .
> . . .
> The lifecycle basis of the LCFS is supposed to ensure that support for low carbon fuels is based on a comprehensive assessment of their climate benefits. However, in this instance, this structure is functioning as poorly designed offset program with transportation fuel users paying an extremely high price for manure methane mitigation. This is not good transportation fuel policy or good agricultural methane mitigation policy.[42]

CARB has a legal duty to address these issues and reform the LCFS to ensure that it supports and furthers the goals and purpose of AB 32 rather than undermining them.

2. The LCFS perversely incentivizes herd expansions, greater geographic concentration of factory farm pollution, and maximum methane generation at factory farms.

CARB's administration of the LCFS perversely incentivizes factory farms to expand to larger herd sizes and to geographically concentrate even more intensively near factory farm gas

[40] Petition, *supra* note 1, at 14–15.
[41] *See* Michael A. Holly et al., *Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture,* 239 AGRIC., ECOSYSTEMS & ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007.
[42] Attach. 6, Letter from Jeremy Martin, Union of Concerned Scientists, to Cheryl Laskowski, CARB (Jan. 6, 2022) (cover letter for study, Attach. 7, urging CARB to reform the LCFS to remove perverse incentives and correct the lack of programmatic integrity caused by faulty LCAs); *see also* Attach. 7, UNION OF CONCERNED SCIENTISTS, QUANTIFICATION OF DAIRY FARM SUBSIDIES UNDER CALIFORNIA'S LOW CARBON FUEL STANDARD (Sep. 2021).

cluster projects or other utility grid access points necessary to monetize factory farm gas pollution under the LCFS. The LCFS also encourages and rewards maximum methane generation from animal manure, disincentivizing strategies that would *avoid* methane generation in the first place.[43] These perverse incentives and the attendant growth in animal numbers at deeply unsustainable factory farms undercut the methane emissions reductions associated with digesters and result in ever greater environmental harms and community health impacts from the plethora of co-pollutants at factory farm operations left unaddressed by anaerobic digesters. CARB cannot continue to bury its head in the sand, ignore the reality on the ground, and delay action on the Petition to reform these serious environmental injustice and program integrity issues.

a. The LCFS causes factory farms to expand.

The LCFS has created a manure "gold rush," driving factory farms to expand their herds to maximize the windfall profits available in the inflated LCFS credit market. Rather than correct the market distortion, the Response instead claims without evidence that "the current LCFS crediting regime for biomethane derived from animal manure is delivering the significant benefits it was designed to achieve."[44] CARB staff invited more data from Petitioners to better establish the expansion problem, which Petitioners provide here.

Petitioners document below at least thirteen recent factory farm expansions undertaken in parallel with digester buildouts and LCFS applications or preparation for LCFS credit generation. This list is not exhaustive, and Petitioners proffer it as a set of examples emblematic of a broader trend. These expansions have occurred in California and other states where factory farming operators have identified the LCFS as a major new source of profit.

Aemetis Advanced Fuels Keyes ("Aemetis") develops dairy biogas cluster projects located in the San Joaquin Valley, and its Aemetis Central Dairy Digester Project[45] provides a case study showing the power of CARB's perverse incentive to expand factory farm herd sizes. CARB has already certified a pathway application from Aemetis to generate LCFS credits from factory farm gas used as a process fuel for ethanol production, and the Central Dairy Digester Project is Aemetis' latest plan to expand its LCFS credit generation.[46] Of the dairies currently identified by Aemetis as part of this cluster project and in various stages of installing anaerobic

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[43] *See supra* note 34 and associated text.

[44] Response, *supra* note 9, at 6. CARB's position can only mean one of two things: either CARB accepts the perverse incentives Petitioners raise and the attendant environmental justice and program integrity issues (including a failure to comply with AB 32's "maximum technologically feasible and cost-effective greenhouse gas emissions reductions" mandate, Health & Safety Code § 38560) as acceptable collateral damage, or CARB has substantively denied Petitioners' claims without a consideration or discussion of the record evidence.

[45] *See Press Releases, Aemetis Receives LCFS Pathway Approval Utilizing Dairy Biogas for Production of Renewable Transportation Fuels*, AEMETIS (Mar. 31, 2021), https://www.aemetis.com/aemetis-receives-lcfs-pathway-approval-utilizing-dairy-biogas-for-production-of-renewable-transportation-fuel/.

[46] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0172 (certified MAR. 29, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0172_cover.pdf.

lagoon digesters,[47] the following seven dairies have recently expanded their herd or are in the process of expanding.

- Ahlem Farms Jerseys[48]
- Vierra Dairy[49]
- S&S Dairy[50]
- Trinkler Dairy[51]
- K&R Blount Dairy[52]
- AJ Borba Dairy[53]
- Oliveira Dairy[54]

As this single cluster project shows, herd expansion necessarily accompanies digester installation to maximize factory farm gas profit under the LCFS. And this example is not an outlier.

Other major factory farm expansions undertaken in tandem with LCFS credit generation plans include, but are not limited to:

- The Melo Dairy expansion and digester install, working with Maas Energy to inject into PG&E pipelines as renewable transportation fuel.[55]

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[47] CAL. ALTERNATIVE ENERGY AND ADVANCED TRANSPORTATION FINANCING AUTHORITY, REQUEST TO APPROVE PROJECT FOR SALES AND USE TAX EXEMPTION 3 (Mar. 16, 2021), https://www.treasurer.ca.gov/caeatfa/meeting/2021/20210316/staff/4.G.8.pdf.

[48] *Use Permit Application No. PLN2020-0081 - Ahlem Farms Jerseys*, CEQANET (received Dec. 10, 2020), https://ceqanet.opr.ca.gov/2020120171/2.

[49] COUNTY OF MERCED, NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL IMPACT REPORT FOR THE VIERRA DAIRY EXPANSION PROJECT (Sept. 2021), https://web2.co.merced.ca.us/pdfs/env_docs/eir/CUP20-009/NOP_IS_2021-09-28_CUP20-009_VierraDairy.pdf.

[50] SJVAPCD, NOTICE OF FINAL ACTION – AUTHORITY TO CONSTRUCT (May 6, 2020), http://www.valleyair.org/notices/Docs/2020/05-14-20_(N-1182555)/Packet.pdf.

[51] SJVAPCD, NOTICE OF FINAL ACTION FOR ISSUANCE OF AUTHORITY TO CONSTRUCT PERMITS (Sept. 12, 2017), https://www.valleyair.org/notices/Docs/2017/09-12-17_(N-1150266)/Newspaper.pdf; *see also* Letter from Jeremy Ballard, Stanislaus County, to Aemetis, Inc. 255–56 (Mar. 25, 2020), https://www.stancounty.com/publicworks/pdf/projects/AemtisBiogasProject/20_10_27_Aemetis%20Biogas%20Pipeline%20ISMND.pdf (discussing digester buildouts at numerous expanding dairies, including Trinkler Dairy, Ahlem Farms Jerseys, K & R Blount Dairy, and S&S Dairy in the context of Aemetis' pipeline construction plans).

[52] *See* STANISLAUS COUNTY PLANNING COMMISSION, USE PERMIT APPLICATION FOR K&R BLOUNT DAIRY EXPANSION (July 16, 2015), https://www.stancounty.com/planning/agenda/2015/07-16-15/VIIA_SR_A_C.pdf (2015 application to allow expanded herd size); CENTRAL VALLEY REGIONAL WATER QUALITY CONTROL BOARD, INSPECTION REPORT, https://ciwqs.waterboards.ca.gov/ciwqs/readOnly/PublicAttachmentRetriever?parentID=33118239&attachmentID=2082677&attType=4 (2018 Inspection Report stating that "K & R Blount Dairy has applied for an expansion").

[53] *Notice of Determination Approving Antonio J Borha Holsteins Dairy Expansion*, CEQANET (Nov. 29, 2018), https://ceqanet.opr.ca.gov/2016121016/4; *see also* COUNTY OF MERCED, ENVIRONMENTAL IMPACT REPORT FOR THE AJ BORBA HOLSTEINS EXPANSION PROJECT (May 2018), https://www.co.merced.ca.us/AgendaCenter/ViewFile/Item/622?fileID=6095.

[54] *Draft EIR for Oliviera Dairy Expansion Project*, CEQANET (Apr. 9, 2019), https://ceqanet.opr.ca.gov/2018081058/2; http://www.valleyair.org/notIces/Docs/2020/06-18-20_(N-1183853)/Packet.pdf.

[55] COUNTY OF MERCED, CONTRACT BOARD AGENDA ITEM, https://web2.co.merced.ca.us/boardagenda/2021/20210713Board/271687/271692/271744/271832/ITEM%2032271832.pdf (providing Melo Dairy Biogas Expansion Project details); *see Press Releases, PG&E, PG&E Helps Advance Accessibility to Renewable Natural Gas Sources*

- The Vander Poel Dairy expansion alongside digester construction, which was subsequently part of Calgren's 2020 LCFS application, which CARB certified.[56]
- Smithfield Foods' massive factory farm expansion in Utah in partnership with Dominion Energy, which plans to use the factory farm gas generated by the new manure lagoons to generate LCFS credits.[57]
- Seven factory farms in Iowa seeking herd expansions along with digester buildouts, accompanied by a developer's intent to use the factory farm gas to generate LCFS credits from at least three factory farms.[58]

These concrete examples of LCFS-related factory farm expansions are only the tip of the iceberg. The manure "gold rush" to monetize factory farm methane pollution can only logically lead to more and more herd expansions and operational decisions that will maximize manure methane emissions, since any manure management decisions designed to proactively avoid methane generation from manure (such as solids separation or dry manure handling) would be held against an applicant when it comes time for CARB to certify a CI for a project. In fact, CARB could hardly have structured a program that would more effectively push these perverse incentives. CARB cannot be so naïve as to think that a program which fundamentally rewards applicants with windfall profits for producing as much manure as possible and managing it in intentionally unsustainable ways has no effect on how factory farms operate, evolve, and impact the environment and local communities.

The factory farm and natural gas industry have identified the LCFS "gold rush" as the new frontier for mega-factory farm development and financial success, with many industry actors and investors recognizing that manure gas has become nearly as valuable, if not more valuable, than milk produced at large dairies. As a manager for one of the largest mega-dairies in the United States said: "The most valuable product we have [at Threemile Canyon dairy in

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for California Customers, PG&E (Jan. 13, 2022), https://www.pge.com/en_US/about-pge/media-newsroom/news-details.page?pageID=db8b414e-5ced-45a3-a31a-5c20203e71f3&ts=1642264019336 (stating that factory farm gas from this cluster of dairies "will make Merced a leading producer of renewable transportation fuels").

[56] SJVAPCD, NOTICE OF FINAL ACTION – AUTHORITY TO CONSTRUCT (May 22, 2019), http://valleyair.org/notices/Docs/2019/05-22-19_(S-1182819)/notice.pdf; CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0098 (certified June 30, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0098_cover.pdf.

[57] Sarah Golden, *The Secret to the Happy Relationship Between Smithfield Foods and Dominion Energy*, GREENBIZ (Feb. 14, 2020), https://www.greenbiz.com/article/secret-happy-relationship-between-smithfield-foods-and-dominion-energy; *see* Lisa Held, *Are Biogas Subsidies Benefiting the Largest Industrial Animal Farms?*, CIVIL EATS (Sept. 20, 2021), https://civileats.com/2021/09/20/are-biogas-subsidies-benefiting-the-largest-industrial-animal-farms/ (discussing Smithfield's massive expansion of hog factory farming in Utah as "part of the company's Align Renewable Natural Gas initiative, created in conjunction with Dominion Energy").

[58] Erin Jordan, *Nine Iowa Dairies Get Digester Permits Since New Law, Seven Plan Expansion*, THE GAZETTE (Dec. 3, 2021), https://www.thegazette.com/agriculture/nine-iowa-dairies-get-digester-permits-since-new-law-seven-plan-expansion/; Kailey Foster, *A Few Hundred Thousand Gallons of Manure Spill at IA Fuel Plant,* KOEL (Feb. 14, 2022), https://koel.com/manure-fuel-spill/ (noting that the digester was intended by Gevo to provide "fuel to power cars in California"); *BP Acquires RNG Project from Gevo*, MANURE MANAGER (Aug. 11, 2021), https://www.manuremanager.com/bp-acquires-rng-project-from-gevo/ (noting the intent to generate LCFS credits); SEC Form 10-Q, https://www.sec.gov/Archives/edgar/data/1392380/000143774921012120/gevo20210331_10q.htm (Gevo disclosure stating that it will source factory farm gas from three dairies and sell into the California market).

Oregon] is natural gas."[59] CARB certified Threemile Canyon's LCFS pathway in 2020.[60]

Recent industry and media statements making a similar point include, but are not limited to:

- "We used to joke about how funny it would be if we could make more money off the poop than the milk," [California mega-dairy Bar 20's] Sheheady said. "And now we're essentially here."[61]
- "If profits are $2 to $3 per hundredweight, they could likely exceed the profit from milk. At that point, milk has become the by-product of manure production."[62]
- "Cow manure is now worth more than milk at some California dairy farms."[63]
- The LCFS "gold rush" is "attracting companies from Amazon to Chevron."[64]
- A principal at a global agribusiness consulting firm noting that cow manure may be worth more than milk in the future—"[s]o, there is a gold rush to install this kind of technology on large-scale dairy farms" in order to profit off the LCFS.[65]

Many other media and industry sources have likewise identified the "gold rush" to monetize intentionally created factory farm methane emissions under the LCFS.[66]

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[59] Tracy Loew, *Manure Is Big Business at Oregon's Largest Dairy with Conversion to Natural Gas*, STATESMAN JOURNAL (Apr. 1, 2019), https://www.statesmanjournal.com/story/tech/science/environment/2019/03/31/oregon-threemile-canyon-farms-dairy-natural-gas-manure/3247197002/.

[60] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0072 (certified Sep. 30, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0072_summary.pdf.

[61] Kaya Laterman, *This California Dairy Farm's Secret Ingredient for Clean Electricity: Cow Poop*, DAILY BEAST (Jan. 22, 2022), https://www.thedailybeast.com/california-dairy-farm-has-microgrid-powered-by-clean-electricity-made-from-methane-from-cow-poop?via=newsletter.

[62] Michael McCully, *Energy Revenue Could Be a Game Changer for Dairy Farms*, HOARD'S DAIRYMAN (Sept. 23, 2021), https://hoards.com/article-30925-energy-revenue-could-be-a-game-changer-for-dairy-farms.html.

[63] *Manure Becomes More Valuable Than Milk at California Dairies*, SBJ (Oct. 20, 2021), https://sbj.net/stories/manure-becomes-more-valuable-than-milk-at-california-dairies,76541#:~:text=Cow%20manure%20is%20now%20worth,can%20exceed%20that%20of%20milk.

[64] Phred Dvorak, *California's Green-Energy Subsidies Spur a Gold Rush in Cow Manure*, WALL STREET J. (Feb. 19, 2022), https://www.wsj.com/articles/californias-green-energy-subsidies-spur-a-gold-rush-in-cow-manure-11645279200.

[65] Emma Hopkins-Obrien, *Dairy Industry Leads the Way for Innovation*, FARMER'S EXCHANGE (Dec. 17, 2021), http://www.farmers-exchange.net/detailPage.aspx?articleID=21153.

[66] *See, e.g.*, Janet Wilson & Joshua Yeager, *Is Manure the Future of Fuel? California Say Yes, but Environmentalists Say It Stinks*, USA TODAY (Mar. 3, 2022), https://www.usatoday.com/story/money/2022/03/03/california-manure-biogas-clean-energy-future-chevron-environmentalists-object/9341873002/?gnt-cfr=1; Marie J. French & Ry Rivard, *Cow Poop and Landfill Gas Shipped to California*, POLITICO (Feb. 14, 2022), https://www.politico.com/newsletters/weekly-new-york-new-jersey-energy/2022/02/14/cow-poop-and-landfill-gas-shipped-to-california-00008502; *California's Dairy Goldrush*, BLUESOURCE (July 20, 2021), https://www.bluesource.com/blog/californias-dairy-goldrush/; Chuck Abbott, *The New California Gold Rush Into Anaerobic Digesters*, SUCCESSFUL FARMING (Feb. 4, 2022), https://www.agriculture.com/news/business/the-new-california-gold-rush-into-anaerobic-digesters; Rachel Cohen, *Why There's a "Gold Rush" to Build Dairy Digesters in Idaho*, BOISE STATE PUB. RADIO (Feb. 11, 2022), https://www.boisestatepublicradio.org/news/2022-02-11/why-theres-a-gold-rush-to-build-dairy-digesters-in-idaho; Frank Jossi, *California Clean Fuel Standard Sparks Renewable Gas Boom in Midwest*, ENERGY NEWS NETWORK

These industry admissions and media coverage of the realities on the ground are not alone; recent economic research indicates that CARB's administration of the LCFS is distorting the dairy market and resulting in a windfall profit for the biggest polluters. A growing number of researchers and agricultural economists are raising alarms about the LCFS's treatment of factory farm gas.

For example, Aaron Smith at the University of California, Davis, found a large gap between the windfall profit received by a factory farm under the LCFS versus the support needed to run and maintain a digester.[67] In other words, the LCFS is rewarding factory farm and factory farm gas developers far beyond what a rational policy would sanction to simply incentivize methane capture. Hence, the "gold rush" will affect how factory farm operators make operational decisions so that they maximize profit. As Mr. Smith concluded, "[the] fact [that manure gas is so overvalued] should make us pause. The large subsidy is de[s]igned to prevent methane emissions that would have happened otherwise. But, what if the farmer adds cows *because of* the subsidy? Then we are no longer paying to reduce emissions."

Additionally, the Union of Concerned Scientists ("UCS") recently worked with researchers at Cal Poly Humboldt to assess LCFS treatment of factory farm gas and reached alarming conclusions.[68] Their analysis similarly found windfall profits that are likely distorting the dairy market. UCS's comments to CARB, noted above, open with their concern that the LCFS is "likely . . . contributing to industry consolidation and putting dairies that use other manure methane strategies at a competitive disadvantage."[69] UCS also warned that "the largest polluter is the one receiving a large subsidy."[70]

Thus, data from the field, anecdotal evidence from industry, statements by key industry players in the media, and academic research all point in the same direction: the LCFS causes perverse incentives that undermine supposed GHG reductions and exacerbate environmental injustice. CARB did not substantively respond to Petitioners' arguments that CARB's treatment of factory farm gas under the LCFS is unlawful for numerous reasons, including due to the expansion and other perverse incentive problems explained above. This additional evidence of the factory farm gas effect underscores the arbitrary and capricious Response.

(May 13, 2021), https://energynews.us/2021/05/13/california-clean-fuel-standard-sparks-renewable-gas-boom-in-midwest/; Andrew R. Skwor & Patrick Wood, *American Dairy at the Carbon Markets – Agriculture's Latest Gold Rush, Part 1*, MSA (Dec. 13, 2021), https://www.msa-ps.com/american-dairy-at-the-carbon-market-agricultures-latest-gold-rush-part-i/; Maxson Irsik, *California Has Carbon Credit Opportunities for Out-of-State Dairies*, HIGH PLAINS JOURNAL (Jan. 20, 2021), https://www.hpj.com/opinion/california-has-carbon-credit-opportunities-for-out-of-state-dairies/article_efd6ebaa-56b9-11eb-a648-c387e359b04e.html; Leah Douglas & Nichola Groom, *Biden Spending Bill Ignites Debate over Dairy Methane Pollution*, REUTERS (Jan. 11, 2022), https://www.reuters.com/markets/commodities/biden-spending-bill-ignites-debate-over-dairy-methane-pollution-2022-01-11/.

[67] Aaron Smith, *What's Worth More: A Cow's Milk or Its Poop?*, AARON SMITH (Feb. 3, 2021), https://asmith.ucdavis.edu/news/cow-power-rising.

[68] *See supra* note 42 and associated text.

[69] *See* Jeremy Martin, *supra* note 42, at 1.

[70] *Id.* at 2.

b. The LCFS causes factory farm herds to consolidate geographically.

Environmental and public health impacts from factory farms do not merely depend on the total aggregate number of dairy cows in California. More relevant factors include where and how those dairies operate. For purposes of explanation, if California's total population of dairy cows is 1.5 million, it matters immensely if 95% of those cows are housed in confinement facilities with liquified manure lagoons in the San Joaquin Valley as opposed to less intensive pasture-based operations. The LCFS has the effect of driving ever greater concentration in the geographic distribution of dairy cows, which negates the argument that small reductions in the overall, statewide dairy cow population somehow makes environmental justice impacts from expanded local herds impossible.

CARB cannot dodge the reality that cluster projects and centralized biogas upgrading and pipeline infrastructure further consolidates the dairy industry in favor of the largest factory farms expanding in close proximity to this infrastructure so that operators can maximize LCFS credits as an immensely profitable source of revenue. As California Bioenergy, one of the leading factory farm gas developers in California, candidly stated to CARB in response to an opposition comment filed by certain Petitioners, "the consolidation of herds to facilities with digesters should be encouraged[.]"[71] It leaves no room for ambiguity when a leading factory farm gas developer has embraced consolidation, and the clear economic signals to market participants like California Bioenergy originate from the LCFS.

Therefore, localized concentration and localized expansions are the relevant metric to assess the environmental justice impacts of CARB's unlawful administration of the LCFS, not the aggregate statewide dairy herd. In fact, without evidence to the contrary, Petitioners believe that any marginal reduction in overall numbers are most likely attributable, at least in part, to the loss of small, more sustainable dairy operations (which are generally unable to benefit from the LCFS) in the face of ever more advantaged mega-dairies now rewarded with an additional and sizeable source of revenue.

3. CARB does not dispute and has arbitrarily and capriciously failed to consider the issue of whether the LCFS may allow non-additional reductions from factory farm gas.

CARB should grant the Petition because the LCFS does not comply with AB 32's mandate that market-based mechanisms ensure the additionality of reductions. The Response failed to consider or otherwise respond to the Petition and the significant number of credits generated by factory farm gas projects that would have otherwise occurred notwithstanding the LCFS. These credits therefore lack validity as market-based compliance instruments, and CARB should not grant further pathway applications that lack additionality. CARB may neither simply ignore this lack of additionality and address it after the Scoping Plan, nor may CARB rely on its misplaced interpretation of section 39730.7(e) of the Health & Safety Code and continue

[71] California Bioenergy, Response to Leadership Counsel for Justice and Accountability, Public Justice, and the Animal Legal Defense Fund (Sept. 29, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_response2.pdf.

authorizing non-additional pathway certifications. The Legislature has established important limits on CARB's authority to implement market-based mechanisms to protect communities and ensure that any voluntary reductions within pollution trading schemes like the LCFS represent real-world emissions reductions. CARB has no authority to override this direction and no authority to ignore the issue while continuing to grant pathway certifications.

As the Petition explains,[72] AB 32 requires that any credits issued for emission reductions under market-based programs must be in addition to (1) "any [GHG] emission reduction otherwise required by law or regulation" and (2) "any other [GHG] emission reduction that otherwise would occur."[73] The LCFS unquestionably meets the definition of a market-based compliance mechanism.[74] The LCFS limits carbon intensity, requires any fuel producer to meet a compliance obligation, and any producer that does not meet the obligation—a deficit holder—must purchase credits to comply with the LCFS.[75] And CARB maintains the LCFS credit bank, acting as a market maker between the purchasers and sellers of LCFS credits.[76]

CARB itself described the LCFS as a market-based mechanism when promulgating amendments to the LCFS:

> The LCFS is a market-based approach designed to reduce the carbon intensity of transportation fuels by 10 percent by 2020, from a 2010 baseline. It is important to note that the Cap-and-Trade Program and the LCFS program have complementary, but not identical programmatic goals: Cap-and-Trade is designed to reduce greenhouse gasses from multiple sources by setting a firm limit on GHGs; the LCFS is designed to reduce the carbon intensity of transportation fuels. As a market-based, fuel-neutral program, the LCFS provides regulated parties with flexibility to achieve the most cost-effective approach for reducing transportation fuels' carbon intensity. . . .
>
> CARB staff disagrees that the LCFS is fundamentally a command-and-control system. The LCFS is a fuel-neutral, market-based program that does not give preference to specific transportation fuels and instead bases compliance on a system of credits and

[72] Petition, *supra* note 1, at 18–24.
[73] § 38562(d)(2).
[74] "Market-based compliance mechanism means either of the following: (1) A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases; and (2) Greenhouse gas emissions exchanges, banking, credits, and other transactions, governed by rules and protocols established by the state board, that result in the same greenhouse gas emission reduction, over the same time period, as direct compliance with a greenhouse gas emission limit or emission reduction measure adopted by the state board pursuant to this division." Health & Safety Code § 38606(k); *see Rocky Mountain Farmers Union v. Corey*, 730 F.3d 1070, 1106 (9th Cir. 2013) (noting the LCFS is a market-based program).
[75] *See, e.g.*, CAL. AIR RES. BD., LCFS BASICS (2019), https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited March 21, 2022).
[76] *See LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS)*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-registration-and-reporting (last visited March 25, 2022).

> deficits based on each fuel's carbon intensity. Carbon intensity (CI) is a measure of the GHG emissions associated with the various production, distribution, and consumption steps in the "life cycle" of a transportation fuel. It is difficult to respond with depth to this assertion because the commenter provides no specifics to support the claim that the LCFS is not market-based. Notably, the commenter does not describe what components of the program could be considered command-and-control.[77]

Additionally, CARB's descriptions of the LCFS program closely parallel the statute's definition of "market-based compliance mechanism." The definition states in relevant part that a market-based compliance mechanism is: "A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases."[78] CARB explains that the LCFS has a "market for credit transactions," where "entities with credits to sell can opt to pledge credits into the market and entities needing credits must purchase their pro-rata share of these pledged credits."[79] CARB explains that credits are generated relative "to a declining CI benchmark for each year."[80] The LCFS exhibits many if not most of the features of a market-based compliance mechanism, including a Cap-and-Trade allowance-like system with yearly declinations,[81] transaction rules,[82] recordkeeping and auditing requirements,[83] an account system to manage credit transfers—the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS)[84]—and a portal that applicants must use to demonstrate compliance,[85] among others. In addition to CARB's interpretation, designation, and treatment of the program as a market-based mechanism and the overall structure of the regulation evincing the same, the

[77] CAL. AIR RES. BD., FINAL STATEMENT OF REASONS FOR RULEMAKING, INCLUDING SUMMARY OF COMMENTS AND AGENCY RESPONSE 679–81 (2015), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/fsorlcfs.pdf; *see also* CAL. AIR RES. BD., RESPONSES TO COMMENTS ON THE DRAFT ENVIRONMENTAL ANALYSIS FOR THE AMENDMENTS TO THE LOW CARBON FUEL STANDARD AND ALTERNATIVE DIESEL FUEL REGULATIONS B4-42 (2018), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/rtcea.pdf (CARB responding, "Because the LCFS is a market-based mechanism…"); CAL. AIR RES. BD., STAFF DISCUSSION PAPER: RENEWABLE NATURAL GAS FROM DAIRY AND LIVESTOCK MANURE 6 (April 13, 2017), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/041717discussionpaper_livestock.pdf (in which CARB staff note in 2017 discussion paper that additionality requirements for the LCFS *are* intended to be identical to those of the compliance offset protocol, "ensure any crediting is for GHG reductions resulting from actions not required by law or beyond business as usual").
[78] CAL. HEALTH & SAFETY CODE § 38505(k). Note that this is one of two definitions provided.
[79] LCFS Basics, *supra* note 75.
[80] *Low Carbon Fuel Standard: About*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Mar. 25, 2022).
[81] *See* CAL. CODE REGS. TIT. 17 §§ 95482–95486.
[82] *See* CAL. CODE REGS. TIT. 17 § 95491.
[83] *See* CAL. CODE REGS. TIT. 17 § 95491.1.
[84] CAL. CODE REGS. TIT. 17 § 95483.2(b). ("The LRT-CBTS is designed to support fuel transaction reporting, compliance demonstration, credit generation, banking, and transfers.").
[85] *See* CAL. AIR RES. BOARD, LOW CARBON FUEL STANDARD – ANNUAL REPORTING AND VERIFICATION USER GUIDE 3-4 (Aug. 9, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/Reporting_and_Verification_User_Guide.pdf.

designation of California's LCFS as a market-based mechanism is ubiquitous in academic and technical literature.[86]

CARB incorporated only one of the additionality prongs into the LCFS, which requires that any credits issued for emission reductions must be "additional to any legal requirement for the capture and destruction of biomethane that are nonadditional emission reductions."[87] And CARB specifically declined to incorporate the additionality requirements contained in the Livestock Protocol to the LCFS.[88] In addition to this flaw in the LCFS itself, CARB's implementation of the LCFS ignores additionality requirements altogether.

CARB presently implements two programs which render a significant number of California-based factory farm gas projects non-additional. First, CARB relies on reductions from the Dairy Digester Research & Development Program (DDRDP) as credit towards the state-wide obligation to reduce methane from manure management as required by SB 1383, codified at Health & Safety Code § 39730.7(b)(1). CARB attributes 1.9 MMTCO2e of methane reductions to 123 dairy digester projects funded by the DDRDP.[89] CARB also identifies future reductions needed to meet the 2030 target, and assumes at least 210 digester projects are needed, in combination with AMMP projects, to achieve 4.4 MMTCO2e of needed methane reductions.[90] Because CARB claims reductions from the same projects as creditable towards the SB 1383 mandate, it may not at the same time authorize those same reductions as additional in the LCFS. As discussed in the Petition, both the California Department of Food & Agriculture and CARB report to the Legislature that appropriated public funds in the DDRDP are responsible for the full reductions by that program.

The same double-counting problem also occurs because of the Aliso Canyon Mitigation Agreement. The Mitigation Agreement legally requires Southern California Gas Company (SoCalGas) to achieve methane reductions from factory farm dairies in California.[91] The parties intended the agreement to mitigate the harms from the most damaging man-made GHG leak in United States history—SoCalGas' ruptured well that released at least 109,000 metric tons of

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[86] *See, e.g.*, CENTER FOR CLIMATE AND ENERGY SOLUTIONS, POLICY CONSIDERATIONS FOR EMERGING CARBON PROGRAMS 2 (June 2016), https://www.c2es.org/wp-content/uploads/2016/06/emerging-carbon-programs.pdf (describing Low Carbon Fuel Standards as an example of a market-based policy option, specifically of a baseline-and-credit program); *Regional Activities*, NATIONAL LOW CARBON FUEL STANDARD PROJECT, https://nationallcfsproject.ucdavis.edu/regional-activities/ (stating California's "LCFS is a market-based mechanism") (last visited Mar. 25, 2022).

[87] *See* Cal. Code Regs. Tit. 17, § 95488.9(f)(1)(B) ("A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of GHG emissions achieved by the voluntary capture of methane, provided that . . . the baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.").

[88] Low Carbon Fuel Standard, Frequently Asked Questions, *supra* note 37, at 5 ("***Additionality requirements*** that are referenced in the Livestock Protocol . . . ***are not required under LCFS***." (emphasis added)).

[89] CAL. AIR RES. BD., ANALYSIS OF PROGRESS TOWARD ACHIEVING THE 2030 DAIRY AND LIVESTOCK SECTOR METHANE EMISSIONS TARGET (DRAFT) 10, Table 1, (June 2021), https://ww2.arb.ca.gov/sites/default/files/2022-03/draft-2030-dairy-livestock-sb1383-analysis.pdf.

[90] *Id*.

[91] *People v. Southern California Gas Company*, Case Nos. BC602973 & BC628120, Appendix A to Consent Decree, Mitigation Agreement, https://www.arb.ca.gov/html/aliso-canyon/aliso-canyon-mitigation-agreement.pdf?_ga=2.146452402.708596706.1633463951-1172357510.1559256345.

methane before it was sealed.[92] SoCalGas funds the construction of digesters and receives "mitigation credits" for the associated emissions reductions. The conditions of the agreement legally require changes intended to reduce emissions and yet at least eight facilities that have generated mitigation credits relied on by SoCalGas have also been part of pathways certified by CARB. California Bioenergy sought and received LCFS credits for the S&S, Moonlight, Hamstra, Trilogy, Maple, T&W, BV Dairy, and Western Sky dairies.[93]

In total, CARB has certified LCFS credits for *at least* six pathways with nonadditional emission reductions. Four of these pathways include projects that had received DDRDP funds and from which CARB claims credit towards the SB 1383 reduction requirement, and two additional pathways were for projects that had received both DDRDP funds *and* delivered reductions as part of the Aliso Canyon Mitigation Agreement, meaning that the same emission reductions have been claimed by three separate programs: the LCFS, the SB 1383 and DDRDP reductions, and by SoCalGas to comply with the Mitigation Agreement.[94] This absurd result means that deficit generators are purchasing illusory credits that do not represent actual emissions reductions and California communities bear the burden of that increased pollution.[95]

4. Factory farm gas causes adverse and disparate environmental impacts.

a) Factory farm gas production exacerbates water pollution.

As discussed in the Petition, dairies throughout the Central Valley actively pollute drinking water with nitrate at levels that exceed drinking water standards, exposing nearby households and communities to unsafe drinking water that can cause Blue Baby Syndrome and that has been linked to cancer.[96] Petitioners cited to several sources demonstrating that nitrate pollution is caused in significant part by dairies, and that pollution is widespread and increasing.

One report in particular bears additional emphasis as CARB considers this Petition for Reconsideration. The Central Valley Summary Representative Monitoring Report[97] was prepared by and for the Central Valley Dairy Representative Monitoring Program, a non-profit

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[92] CAL. AIR RES. BD., RESPONSES TO FREQUENTLY ASKED QUESTIONS: ALISO CANYON LITIGATION MITIGATION SETTLEMENT, https://ww3.arb.ca.gov/html/aliso-canyon/aliso-canyon-faqs.pdf?_ga=2.67705041.1139070712.1533833674-1489205872.1532954259.

[93] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0185 (certified Sep. 30, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_cover.pdf; CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0198 (certified Sep. 30, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

[94] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B0019 (DDRDP); B0104 (DDRDP); B0106 (DDRDP); B0172 (DDRDP); B0185 (DDRDP and Alison Canyon settlement); B0198 (DDRDP and Aliso Canyon settlement). Note that many pathways, including these, are tied to multiple large factory farm gas operations. In this case, though there were only two pathways that received funds from DDRDP and the Aliso Canyon settlement, there were eight factory farm gas operations.

[95] *See* Petition, *supra* note 1, at 11; 20–23; 37 (explaining details).

[96] *Id.* at 29–30.

[97] CENTRAL VALLEY DAIRY REPRESENTATIVE MONITORING PROGRAM, SUMMARY REPRESENTATIVE MONITORING REPORT (REVISED*) (Apr. 19, 2019), https://www.waterboards.ca.gov/centralvalley/water_issues/confined_animal_facilities/groundwater_monitoring/srmr_20190419.pdf.

association of dairy owners and operators, in response to direction from the Central Valley Regional Water Quality Control Board.[98] It thus contains the conclusions of representatives of the dairy industry itself, and presents years of monitoring data from forty-two Central Valley dairies chosen to be representative of the industry in the region.

As an industry report, its findings regarding widespread and continuing nitrate pollution should be afforded substantial weight. Some of the key conclusions from the report include:

- "CVDRMP's data set documents that elevated nitrate-N (i.e., as nitrogen) concentrations were present beneath ***all monitored dairies***."[99]
- "… mean groundwater nitrate-N concentration beneath dairies overlaying shallow groundwater (<55 feet deep) was 48 mg/L (median=35 mg/L) and 38 mg/L in deeper groundwater (median=35 mg/L). The mean groundwater nitrate-N concentration in areas of permeable soils was 59 mg/L (median=46 mg/L) and 29 mg/L (median=21 mg/L) in areas of clay-rich soils."[100]
- "…approximately 94 percent of nitrogen loading on dairies (that is, the portion of nitrogen that enters the soil and is not recovered by plants) occurs on cropland."[101]
- There is evidence of a "substantial amount of 'unaccounted-for' manure nitrogen" on many dairies, indicating that dairy reporting regarding field applications has been inaccurate and applied nitrogen has been underreported.[102]
- Dairies have an "excess supply of nitrogen" in the form of manure than can be safely applied to cropland without causing or contributing to nitrate pollution.[103]
- "To date, implementation of the Dairy Order does not appear to have resulted in a trend to lower nitrate-N concentrations across the industry."[104]

To summarize these findings, the dairy industry representatives have acknowledged in a thorough report required by the Regional Water Board that all representative dairies are actively polluting groundwater with nitrate, that the problem is caused by excess supply (i.e., too much manure to be safely applied to the dairies' cropland currently used for manure disposal), and that the Dairy Order has not resulted in a trend to lower nitrate concentrations to date.

Nitrate pollution caused by Central Valley dairies is a vast problem impacting most (if not all) dairy operations in the region. The problem is only exacerbated when a dairy increases its herd size, thus increasing its "excess supply" of manure. This is true even if the increased herd size on a particular dairy is accompanied by the reduction in herd size in the region overall. Nitrate pollution in groundwater is a hyper-local issue, primarily impacting nearby households and communities that rely on downgradient groundwater for drinking, cooking, and other

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[98] *Id.* at a.
[99] *Id.* at 6 (internal citation omitted) (emphasis added).
[100] *Id.*
[101] *Id.* at 10.
[102] *Id.*
[103] *Id.*
[104] *Id.* at 6–7.

domestic purposes. CARB cannot ignore these impacts as it adopts and implements policies that incentivize additional manure production at individual dairies participating in the LCFS.

b) Factory farm gas production exacerbates water consumption.

Dairies have already dealt serious damage to California's water resources, and perversely incentivizing their expansion and consolidation in the most parched region of the state exacerbates the effects of the ongoing historic megadrought.[105] These industrial facilities consume "a massive amount of water" for various operational purposes, such as flushing manure, watering animals, and irrigating the crops upon which they rely for manure and digestate management.[106] In addition, dairies rely upon water-intensive crops to feed dairy cows. Those crops consume more than ten million acre-feet of water—or twenty percent of all water used in California—each year.[107] Overall, animal agriculture is responsible for forty-seven percent of California's total water footprint.[108]

To feed their extreme water consumption, dairies seek sites above major aquifers and treat groundwater as a "free good" after they pump it from the ground.[109] The San Joaquin Valley, where many mega dairies and methane digesters are operating, is ground zero for critical groundwater overdraft and water scarcity.[110] Thousands of private and community water wells, upon which many Californians rely for drinking water, have already run dry.[111] Further industry consolidation and expansion from the manure "gold rush" would further tap scarce groundwater resources in order to produce methane-based fuels when operators could instead avoid water intensive liquefied manure management.

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[105] A. Park Williams et al., *Rapid intensification of the emerging southwestern North American megadrought in 2020-2021*, 12 NATURE CLIMATE CHANGE 232 (Mar. 2022); A. Park Williams et al., *Large contribution from anthropogenic warming to an emerging North American megadrought*, 368 SCIENCE 314 (Apr. 17, 2020).
[106] *See, e.g.*, WILLIAM J. WEIDA, CONCENTRATED ANIMAL FEEDING OPERATIONS AND THE ECONOMICS OF EFFICIENCY 22 (Mar. 19, 2000), https://www.sraproject.org/wp-content/uploads/2017/10/cafosandtheeconomicsofefficiency.pdf.
[107] Justin Fox, *Why California Needs Thirsty Alfalfa*, BLOOMBERG (May 26, 2015), https://www.bloomberg.com/opinion/articles/2015-05-26/why-they-grow-thirsty-alfalfa-in-parched-california; *see generally* James McWilliams, *Meat Makes the Planet Thirsty*, N.Y. TIMES (Mar. 7, 2014), https://www.nytimes.com/2014/03/08/opinion/meat-makes-the-planet-thirsty.html ("Grown on over a million acres in California, alfalfa sucks up more water than any other crop in the state. And it has one primary destination: cattle.").
[108] JULIAN FULTON ET AL., CALIFORNIA'S WATER FOOTPRINT 3 (Dec. 2012), PACIFIC INST., https://pacinst.org/wpcontent/uploads/2013/02/ca_ftprint_full_report3.pdf.
[109] Weida, *supra* note 106, at 22.
[110] *Critically Overdrafted Basins*, CAL. DEP'T OF WATER RES., https://water.ca.gov/programs/groundwater-management/bulletin-118/critically-overdrafted-basins (last visited Mar. 22, 2022) (showing most groundwater basins and subbasins in the San Joaquin Valley are critically overdrafted); *see* ELLEN HANAK ET AL., WATER AND THE FUTURE OF THE SAN JOAQUIN VALLEY (2019), PUB. POL. INST. OF CAL., https://www.researchgate.net/publication/331476376_Water_and_the_Future_of_the_San_Joaquin_Valley.
[111] *Groundwater Management and Drought: An Interview with the San Joaquin Valley Partnership*, CAL. DEP'T OF WATER RES., (Mar. 8, 2022), https://water.ca.gov/News/Blog/2022/March-22/Groundwater-Management-and-Drought-An-Interview-with-the-San-Joaquin-Valley-Partnership (noting that groundwater overdraft is causing domestic well owners to "lose access to their primary source of drinking water," leaving them unable to "afford or obtain services due to drilling backlogs or financial challenges" and forcing them to seek out and rely on emergency sources of drinking water); *see* Jelena Jezdimirovic et al., *Will Groundwater Sustainability Plans End the Problem of Dry Drinking Water Wells?*, PUB. POL'Y INST. OF CALIFORNIA (May 14, 2020), https://www.ppic.org/blog/will-groundwater-sustainability-plans-end-the-problem-of-dry-drinking-water-wells/.

Moreover, factory farm gas production relies upon methane digesters, which require "abundant water resources, with a proportion equal to 1:1 of the amount of water and manure to be loaded into the digester,"[112] to pump and dilute manure.[113] In arid climates it may be necessary to pump groundwater for this purpose.[114]

c) Factory farm gas interferes with efforts to attain air quality standards and inflicts disparate impacts on the basis of race and income.

Fuels derived from factory farm gas have a significant negative impact on air quality in the San Joaquin Valley, which result in a racially disparate impact in violation of Government Code § 11135 and Title VI of the Civil Rights Act. Moreover, AB 32 requires that CARB must ensure its policies do not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[115] CARB must also ensure that "activities undertaken to comply with the regulations do not disproportionately impact low-income communities."[116] The LCFS and pathways certified by CARB inflict racially and economically disparate impacts and interfere with efforts to achieve and maintain federal ambient air quality standards in two significant ways. First, anaerobic digesters increase ammonia emissions, which in turn reacts with oxides of nitrogen (NOx) to form ammonium nitrate, which significantly contributes to fine particulate matter (PM2.5) pollution. Second, digester engines powering turbines to generate electric vehicle fuel pathways emit significant and unabated additional NOx, PM2.5, and volatile organic compound (VOC) emissions in the air basin. Combined, both effects exacerbate the PM2.5 pollution crisis in the San Joaquin Valley.

The U.S. Environmental Protection Agency's EJSCREEN mapping tool[117] produced the two maps below which show the racially disparate impact visually with the stark contrast between the Valley and the rest of California.

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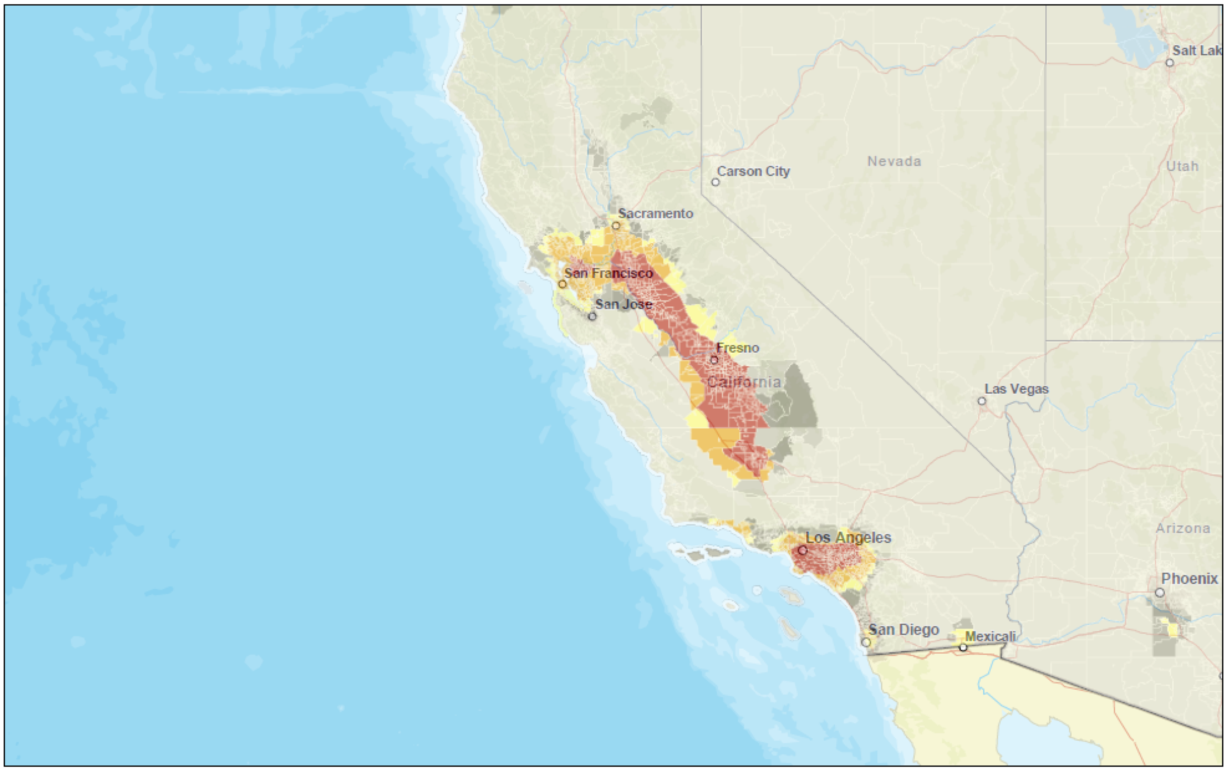
[112] Tatiana Nevzorova & Vladimir Kutcherov, *Barriers to the wider implementation of biogas as a source of energy: A state-of-the-art review*, 26 ENERGY STRATEGY REVIEWS 7 (Oct. 14, 2019), https://www.sciencedirect.com/science/article/pii/S2211467X19301075#bib113.
[113] ENVTL. PROTECTION AGENCY, AGSTAR, PROJECT DEVELOPMENT HANDBOOK: A HANDBOOK FOR DEVELOPING ANAEROBIC DIGESTION/BIOGAS SYSTEMS ON FARMS IN THE UNITED STATES 9-5, https://www.epa.gov/sites/default/files/2014-12/documents/agstar-handbook.pdf (3rd Ed.).
[114] *Id.*
[115] § 38562(b)(4).
[116] § 38562(b)(2).
[117] *See EJSCREEN: Environmental Justice Screening and Mapping Tool*, ENVTL. PROTECTION AGENCY, https://www.epa.gov/ejscreen (last visited Mar. 25, 2022).

PM2.5 Levels in the Ambient Air



1/21/2022

EJSCREEN_Indexes

Data not available

Less than 50 percentile

50 -60 percentile

60 -70 percentile

70 -80 percentile

80 - 90 percentile

90 - 95 percentile

95 - 100 percentile

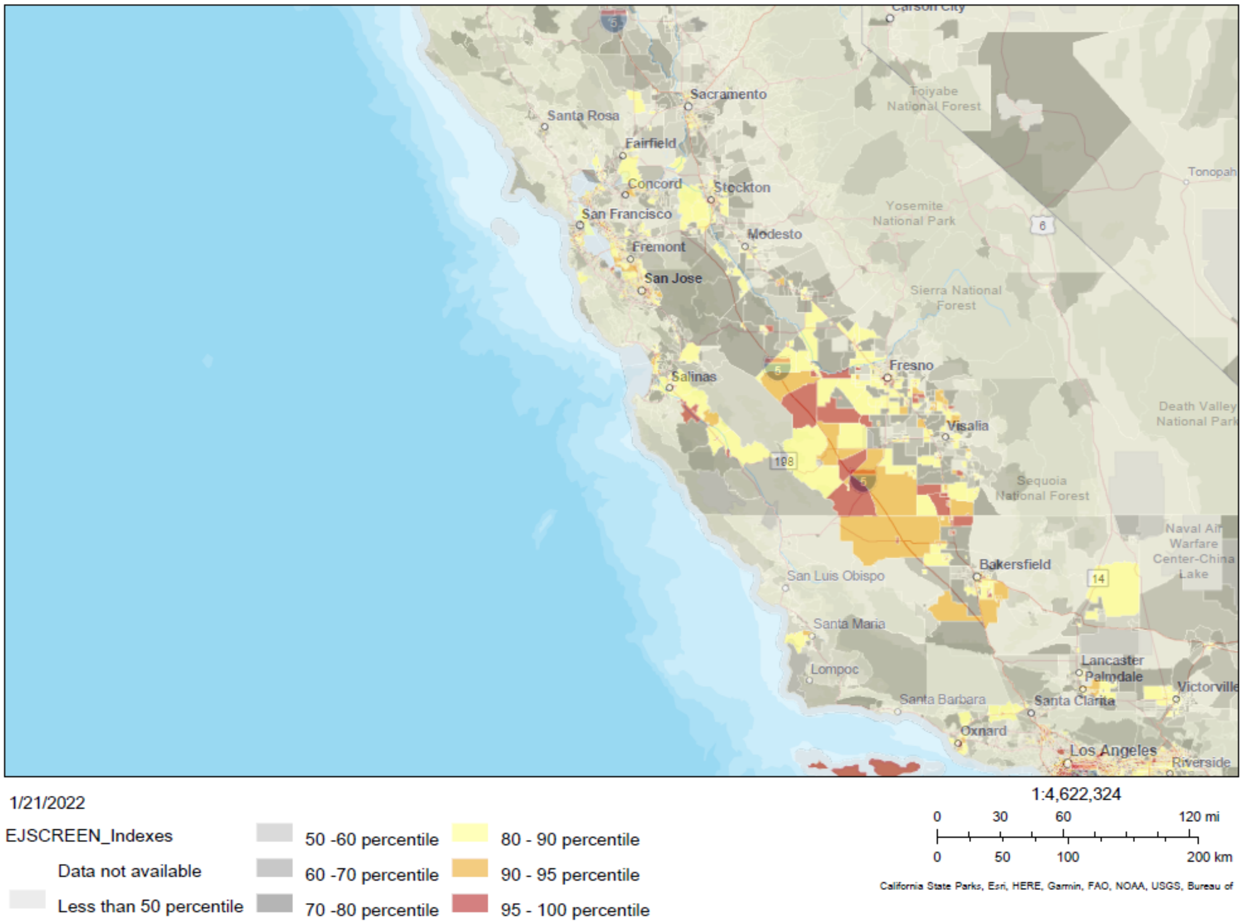
1:9,244,649

0 62.5 125 250 mi

0 100 200 400 km

California State Parks, Esri, HERE, Garmin, FAO, NOAA, USGS, EPA

People of Color Populations



Recent scientific research literature favorably cited by EPA finds that "emission sources that disproportionately expose [people of color] are pervasive throughout society."[118] Tessum notes that disparities *nationally* are most related to PM2.5 from transportation fuels. The San Joaquin Valley, however, presents a unique rural racial demographic with much higher populations of people of color compared to the rest of rural and urban California, and higher PM2.5 exposure since the Valley has the worst long term PM2.5 concentrations and hence the highest design values with respect to the 2012 annual PM2.5 national ambient air quality standard. Ammonia reacts with nitric oxide in the atmosphere to form ammonium nitrate, which comprises 38 percent of the PM2.5 mass on an annual average basis in Bakersfield, and 61

[118] Attach. 8, Christopher W. Tessum, et al., *PM2.5 polluters disproportionately and systemically affect people of color in the United States*, 27 SCI. ADVANCES (Apr. 28, 2021), https://www.science.org/doi/epdf/10.1126/sciadv.abf4491; Attach. 9, *Study Finds Exposure to Air Pollution Higher for People of Color Regardless of Region or Income*, ENVTL. PROTECTION AGENCY (Sept. 20, 2021), https://www.epa.gov/sciencematters/study-finds-exposure-air-pollution-higher-people-color-regardless-region-or-income#:~:text=In%20the%20United%20States%2C%20people,%2C%20Climate%2C%20and%20Energy%20Solutions.

percent on high PM2.5 days.[119]

The "disadvantaged communities" of California, as defined pursuant to California Senate Bill 535, are concentrated in the San Joaquin Valley.[120] Seven of the eight counties in the Valley (all except San Joaquin County) report mean income well below the 120% limit that defines low-income.[121] Every county in the San Joaquin Valley has lower household and per capita incomes, and higher poverty rates than California as a whole.[122] While median household income in California in 2019 was $75,235, countywide household median incomes for San Joaquin Valley counties ranged from $49,687 to $64,432. The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $53,672 and $49.687—both at 71 percent or below statewide median income.[123]

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[119] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS 3-2 to 3-3 (Nov. 15 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.

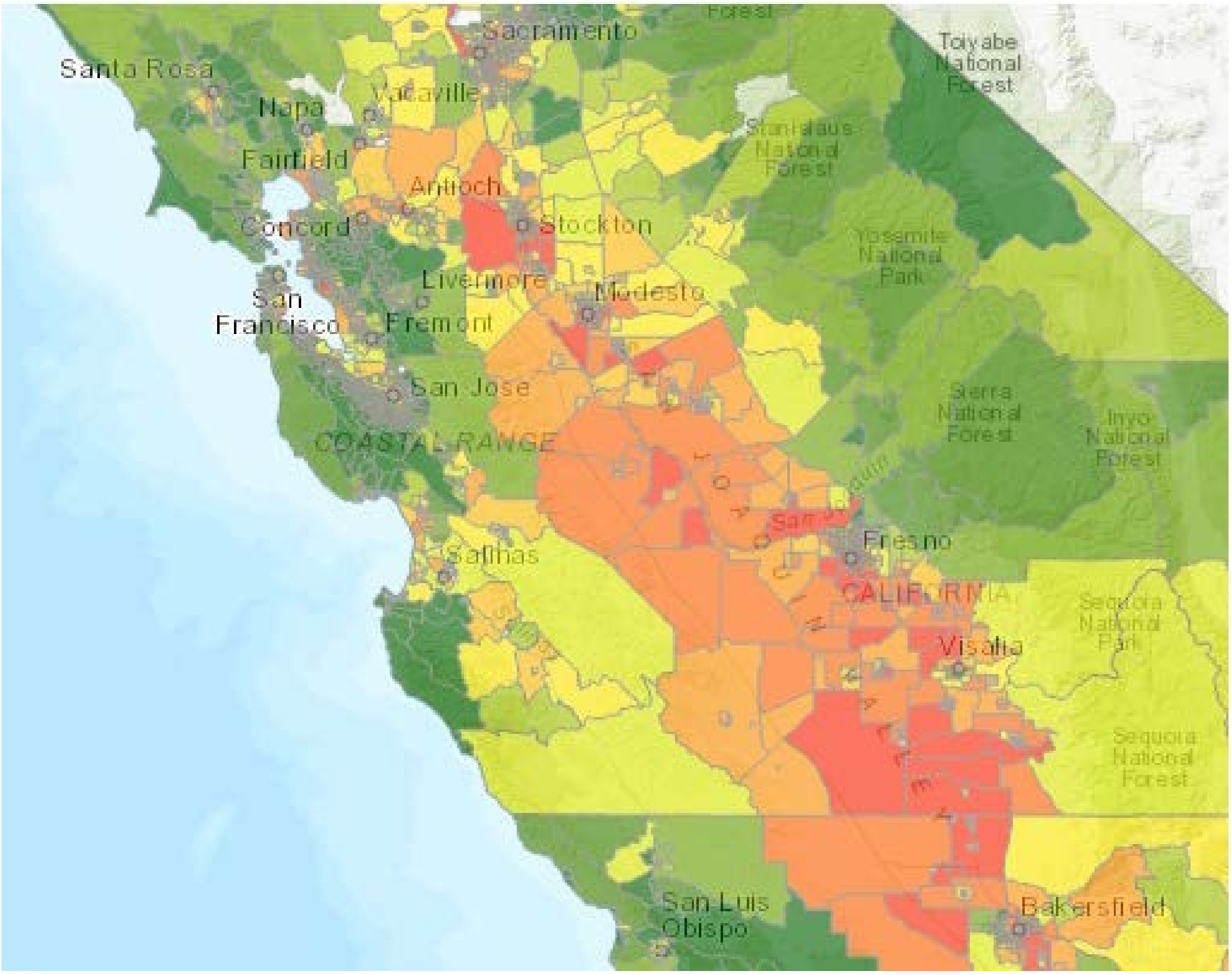
[120] CALEPA, DESIGNATION OF DISADVANTAGED COMMUNITIES PURSUANT TO SENATE BILL 535 (DE LEÓN) 1-32 (Apr. 2017), https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf. All eight counties of the San Joaquin Valley exhibit the highest scores indicating the greatest pollution burden relative to the rest of California. *See Maps & Data*, CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Mar. 25, 2022) (flagging areas of California that exhibit high to low pollution burden scores); *see also infra* page 27, San Joaquin Valley CalEviroScreen 4.0 map.

[121] Section 39711 of the Health and Safety Code sets the ceiling for low-income communities at 120% of the area median income. Additionally, Section 39711 designates communities with disproportionate environmental impacts and concentrations of low income, high unemployment, low educational attainment, and other burdensome socioeconomic factors as disadvantaged communities. Attach. 10, *Income Limits*, U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il.html#2020_data (last updated Apr. 1, 2020) (choose 30% Income Limit for ALL Areas (Excel)); Attach. 11, *FY 2020 State Income Limits* (2020), U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il/il20/State-Incomelimits-Report-FY20r.pdf.

[122] Attach. 12, *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Mar. 25, 2022).

[123] Poverty rates in every single county in the San Joaquin Valley also exceed poverty rates in California, with Merced and Tulare facing 17 and 18.9 percent poverty rates, respectively (as compared to 11.8 percent at the statewide level). *Id.*

San Joaquin Valley, CalEnviroScreen 4.0



San Joaquin Valley residents are disproportionately Latino as compared to California as a whole. All eight San Joaquin Valley Counties have higher Latino populations than the state, with populations ranging from 42 percent to 65.6 percent, as compared to the state population with 39.4 percent of residents classified as Latino. At least seven of eight San Joaquin Valley counties have a lower proportion of white residents as compared to the state as a whole.[124] Merced and Tulare counties have white, non-Latino populations of 26.5 and 27.7 percent, and Latino populations of 65.6 and 61 percent, respectively.[125] Like Merced and Tulare, Kern County also demonstrates much higher Latino populations than the rest of the state, with a Latino population of 54.6 percent.

[124] According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Id.*
[125] *Id.* at 114.

i. Factory farm gas increases ammonia emissions.

Industrial dairies in the San Joaquin Valley are the largest source of ammonia.[126] Factory farm gas production adds even more ammonia to the air basin: one study documents that ammonia emissions from digestate increased 81% relative to raw manure.[127] Anaerobic digestion causes this increase in ammonia emissions, "due to an increased concentration of ammoniacal nitrogen."[128] Ammonia reacts with oxides of nitrogen to form ammonium nitrate, the most significant component of the San Joaquin Valley's PM2.5 pollution problem.[129]

CARB has analyzed the impact of ammonia emissions on ambient PM2.5 as part of the recent 2018 PM2.5 Plan for the Valley. CARB found that ammonia contributed 5.2 $\mu g/m^3$ to the ambient air and found that a 30 percent and 70 percent reduction in ammonia would result in a range of ambient reductions in PM2.5 from 0.08 to 2.3 $\mu g/m^3$.[130] For context, the 2012 annual PM2.5 standard is 12 $\mu g/m^3$.[131] The overall contribution of ammonia from current dairy activities would only increase as more anaerobic digesters cause an increase in ammoniacal nitrogen in the digestate and thus increase ammonia emitted into the air basin. This air pollution impact interferes with efforts to attain the PM2.5 24-hour and annual standards and causes a disparate impact on the basis of race and income. CARB cannot ignore this reality and must grant the Petition.

ii. Factory farm gas electricity pathways increase ozone and PM2.5 precursors.

The Petition identifies the on-site combustion of factory farm gas using internal combustion engines to power turbines for electricity generation at dairy operations as a significant air quality impact in the San Joaquin Valley Air Basin.[132] This form of factory farm gas fuel pathway to generate LCFS credits produces negative CI fuel pathways designated for electric vehicles. For example, CARB certified a pathway for such fuel generated at the Hilarides Dairy for a -758.46 CI in B016301[133] and at the Bidart-Old River Dairy for a -558.62 CI in B005901.[134] To date, Petitioners have identified eight certified pathways generating electric vehicle fuel in factory farm gas-powered engines, all located in the San Joaquin Valley, and an

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[126] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.

[127] *See* Holly, et al., *supra* note 41.

[128] *Id.*

[129] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.

[130] SJVAPCD, 2018 PM2.5 PLAN, APPENDIX G, 3 and tables 2 through 7 (Oct. 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.

[131] *See* 78 Fed. Reg. 3086 (Jan. 15, 2013).

[132] Petition, *supra* note 1, at 30.

[133] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B016301 (certified June 21, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0163_cover.pdf.

[134] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B005901 (re-certified Mar. 25, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0059_cover.pdf.

additional number of similar facilities out of state.[135] Petitioners have further identified an additional three pending pathway certification applications, including one for the Lakeview Dairy.[136]

These fuel pathways represent a pollution-intensive form of fuel and one that rewards the developer with an extremely low CI value, creating an incentive to further develop this form of fuel pathway and thus even more air pollution in the Valley. To illustrate, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site and has applied for a fuel with a -382.98 CI value.[137] And this project, as permitted by the Air District with required pollution control technology, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM2.5, and 3.18 tons/year of VOC after the imposition of Best Available Control Technology as required by the State Implementation Plan.[138] Compared to a natural gas combined cycle plant in Avenal also permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, sulfur oxides (SOx), and VOC emissions per unit of electricity generated.[139] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase emission reduction credits for the air pollution emitted.[140] This facility *increases* air pollution in the San Joaquin Valley.

With eight certified pathways and at least three more pending, CARB will soon be allowing the functional equivalent of the Avenal Power Center operating at about 50 percent capacity and without having offset that pollution with emission reduction credits. Another dozen electric fuel pathways powered by factory farm gas-fueled engines at Valley dairies would emit the same amount of NOx pollution as Avenal at full capacity, but only generate 4.4 percent of the electricity.[141] A similar pattern results from the emissions of VOCs.[142] This absurdity is compounded by Air District offset thresholds such that the digester engines do not buy emissions offsets and thus add more air pollution to the air basin, while in theory the Avenal Power Center would have had to purchase offsets from other sources to achieve a no net increase. This occurs in one of the most polluted air basins in the United States and classified as nonattainment for several fine particulate matter National Ambient Air Quality Standards.[143] CARB has effectively allowed the LCFS to add more air pollution to the San Joaquin Valley, call it "renewable" fuel

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[135] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B001901, B003701, B008901, B005901, B016601, B003801, B002401, and B016301.

[136] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B0104, B0105, and B0106.

[137] SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf; CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0104 (certified TBD), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.

[138] SJVAPCD, *supra* note 137, at 14.

[139] Attach. 13, Digester v. Avenal Comparison; Attach. 14, SJVAPCD, NOTICE OF FINAL DETERMINATION OF COMPLIANCE, AVENAL POWER CENTER, 3, 27 (Dec. 17, 2010). Producing 1.059 megawatts and emitting 4.58 tons/year of NOx, the Lakeview turbine generates 0.17 percent of the electricity while the engines powering the turbine emit 4.6 percent of the NOx pollution.

[140] Attach. 15, SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT 14 (Mar. 22, 2016).

[141] Digester v. Avenal Comparison, *supra* note 139. This assumes that Lakeview represents the average emissions from these factory farm gas operations.

[142] *Id*.

[143] 80 Fed. Reg. 18,528 (April 7, 2015); 81 Fed. Reg. 84,481 (November 23, 2016); 80 Fed. Reg. 2,206, 2,217 (January 15, 2015).

for electric vehicles, and then allows credits from that fuel to be sold to fossil fuel deficit holders who then may increase the pollution from their fuels sold in California. By allowing polluting factory farm gas to generate credits for "renewable" electric vehicle fuel, despite the harmful health impacts associated with emissions from the use of factory farm gas to generate that electricity, CARB ignores its statutory obligation not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[144] CARB must also grant the Petition and ensure the LCFS-related air pollution does not inflict a disparate impact on the basis of race, and must ensure that the LCFS complies with AB 32, Government Code § 11135, and Title VI of the Civil Rights Act.

d. Factory farm gas fuels consume significant energy inputs to produce which render factory farm gas much more pollution intensive than previously disclosed.

As noted above, Petitioners have submitted comments on dozens of pathway certifications and consistently have objected to the heavy redaction of information as proprietary and confidential business information. Until recently, Petitioners have not seen some of the fuel inputs for factory farm gas development as a result of this heavy-handed redaction. But recently, fuel pathway applications from Wisconsin-based factory farm gas operators shed much-needed transparency on the energy-intensive generation of factory farm gas. CARB should grant the Petition and, because such information was unavailable at the time of the Petition, also consider and disclose net energy consumption when calculating the CI values for factory farm-gas derived fuels.

First, the significance of the redactions to date have rendered meaningful public review of fuel consumption and energy inputs impossible. Below is an example of an application from a Sacramento-area factory farm gas project which claimed one of the largest negative CIs.[145]

[144] § 38562(b).
[145] SMUD, NEW HOPE DAIRY DIGESTER GREET LCFS PATHWAY TO PRODUCE ELECTRICITY TO CHARGE ELECTRIC VEHICLES IN SMUD REGION & CALIFORNIA (Dec. 4, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0166_1_report.pdf.

Sacramento 1500 Cow dairy 06/03/2021

4. Life Cycle Results for Carbon Intensity

The calculated Carbon Intensity for New Hope dairy digester system to charge electric vehicles = **-750.81 gCO_{2e}/MJ**, see table below.

[redacted]

Page | 8 New Hope Dairy Digester to EV Pathway Application No. B0166 Facility ID: F00255 Copyright © 2020

Still other pathway applications fully redact all input data and only disclose the final CI. This CI calculation from the Western Sky Dairy in Kern County illustrates this degree of redaction.[146]

Exhibit 25. Total Carbon Intensity for Dairy Manure Pathway-Western Sky Biogas LLC

Process Stage	Carbon Intensity (gCO_2e/MJ Biogas)
Diesel Consumption	[redacted]
Electricity Consumption	[redacted]
Loss/Fugitives	[redacted]
Biomethane Transmission	[redacted]
Compression of CNG	[redacted]
Tailpipe Emissions	[redacted]
Methane Avoided	[redacted]
CO_2 Diverted	[redacted]
Final CNG CI (gCO_2e/MJ)	-385.40

09/30/2021 Kern County, CA

[146] CALIFORNIA BIOENERGY, LIFE-CYCLE ASSESSMENT OF DAIRY MANURE BIOGAS TO CNG (Sep. 30, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_report.pdf. Also noteworthy is the fact that Western Sky Dairy is one of the eight dairies generating reductions credited towards the DDRDP, the Aliso Canyon Mitigation Agreement, and the LCFS.

On February 25, 2022, CARB posed a Tier 2 pathway application for factory farm gas CNG fuel for pipeline injection at Kinnard Farms in Wisconsin.[147]

III. GREET Results

Exhibit 8 shows the extracted results from a table created on the "Biogas to RNG" tab for the dairy manure in Section 4 of the Tier 1 calculator.

Exhibit 8. Total Carbon Intensity for RNG Produced

Process Stage	Carbon Intensity (gCO_2e/MJ)
Raw Biogas Production-Digester	42.23
Biogas Upgrading	116.06
NG Transmissions	11.99
RNG Compression	3.50
Combustion	60.73
Methane Credit	-614.14
CO_2 Diverted	-0.07
Total – (gCO_2e/MJ)	**-382.83**

Kinnard Frarms, Wisconsin, 2022

B0216

These data show that for Kinnard Farms, the CI of the fuels to produce the factory farm gas have a total CI of 173.70. The actual fuels used to produce the gas are redacted. But if we assume conservatively that these fuels (likely a combination of electricity, diesel, and natural gas) have an average CI themselves of 100 then we can approximate the energy consumed to produce the factory farm gas. The estimate in this case is that 1.7370 MJ of energy has been consumed to produce 1.0 MJ of the final factory farm gas product.

There are two disturbing conclusions from this analysis. One, the energy to produce the factory farm gas is greater than the energy in the final product which demonstrates the entire process to be inherently unsustainable in terms of this energy balance. The EROI (Energy Return on Investment) for this situation is approximately 0.58. An EROI less than 1.0 is not sustainable in any other area of energy production. The second issue here is the fact that these energy inputs (to the extent they are not based on electricity from solar, wind or water) all produce pollution from combustion and most of that pollution is localized. Until some of these numbers were given to the public in recent applications, there was no way of knowing the extent of pollution and energy consumed in the operation of these digesters and the subsequent cleaning, upgrading, compressing and transport of the resulting fuel.

B. SB 1383 mandates neither the inclusion nor the overvaluation of factory farm gas in the LCFS.

CARB should grant the Petition because the Response erroneously interprets SB 1383 as a mandate to include factory farm gas in the LCFS such that the Executive Officer could not grant the relief sought in the Petition. Nor does SB 1383 mandate CARB include inflated LCFS credits from grossly negative CI values or include illusory credits from non-additional reductions

[147] DTE Energy Trading, Kewuanee RNG Production Pathway (Oct. 21, 2021) https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0216_lca.pdf.

from other programs. The Executive Officer's categorical rejection of the Petition applies the law as if the Legislature bound CARB's authority and denied the agency any choice other than including factory farm gas in the LCFS. Specifically, the Executive Officer interprets Health & Safety Code § 39730.7(e) as a binding legislative command that "directs CARB to 'ensure' LCFS crediting of methane reductions" and that CARB must comply with this "statutory direction" to authorize LCFS credits for factory farm gas.[148]

Neither section 39730.7(e) nor its legislative history direct CARB to include factory farm gas in the LCFS. Instead, the statutory provision seeks to respond to an entirely different legislative concern with respect to the validity of credits generated given CARB's authority elsewhere in SB 1383 to adopt regulations that mandate methane reductions from manure management.

> No later than January 1, 2018, the state board shall provide guidance on credits generated pursuant to the Low-Carbon Fuel Standard regulations (Subarticle 7 (commencing with Section 95480) of Title 17 of the California Code of Regulations) and the market-based compliance mechanism developed pursuant to Part 5 (commencing with Section 38570) of Division 25.5 from the methane reduction protocols described in the strategy and *shall ensure that projects developed before the implementation of regulations adopted pursuant to subdivision (b) receive credit for at least 10 years.* Projects shall be eligible for an extension of credits after the first 10 years to the extent allowed by regulations adopted pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500)).[149]

This provision to ensure credit for projects makes sense when read in the context of the overall statutory scheme. In another provision of SB 1383, the Legislature directed CARB to adopt mandatory methane reductions from manure management and gave CARB discretion on when CARB could implement such regulations, but not earlier than January 1, 2024.[150] And since SB 1383 responded to the unabated methane emitted by manure management with this regulatory mandate, section 38562(d)(2) of the Health & Safety Code would render such reductions non-additional upon the adoption of such regulations. And thus, the narrowly drawn grandfathering language in section 39730.7(e) the Legislature adopted does not concern the eligibility to sells credits in the LCFS as a matter of right, but rather the additionality of any valid credits generated prior to the regulations.

The Legislature thus did not direct CARB to include factory farm gas in the LCFS as the Executive Officer interprets in SB 1383. And the legislative history supports the plain meaning of the statutory language. The dairy amendments to SB 1383 occurred within the final 24 hours of the legislative session, and the Senate floor analysis documents the purpose of section 39730.7(e) as a grandfathering mechanism. Moreover, none of the committee reports indicate

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[148] Response, *see supra* note 9, at 3, 5.
[149] § 39730.7(e) (emphasis added).
[150] Health & Safety Code § 39730.7(b)(1), (b)(4).

any legislative intent to require that CARB include factory farm gas in the LCFS.[151] As a result, the Response denying the relief sought by the Petition is contrary to law and otherwise arbitrary and capricious, and the Board should grant the Petition.

C. San Joaquin Valley communities cannot wait until 2023 or later for CARB to address the issues raised in the Petition, which disproportionately harm them.

The Response states that it would be premature to amend the LCFS at this time because the Scoping Plan is scheduled to be updated by the end of 2022.[152] This is akin to stating that it would be premature to shut off a firehose spraying gasoline on a house fire because the proper report has not yet been filed. CARB's administration of the LCFS as to factory farm gas is fueling the expansion and consolidation of an industry that is sickening and *killing* San Joaquin Valley residents. This is an emergency, and CARB must respond accordingly.

The Petition and this Petition for Reconsideration highlight the ways in which the dairy industry is already harming San Joaquin Valley residents, who CalEnviroScreen designates as a "sensitive population."[153] First and foremost, dairy air pollution is killing San Joaquin Valley residents. As the Petition notes, CARB admits that PM2.5 exposure *alone* "is responsible for about 1,200 cases of premature death in the Valley each year."[154] And dairy air pollution is also sickening these residents, who experience higher rates of asthma, low birth weight, and cardiovascular disease compared to state incidence rates.[155] Sometimes the air is so dangerous to breathe that local authorities recommend schools hold recess indoors, depriving children of access to outdoor recreation.[156] As described above, factory farm expansion and consolidation in

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[151] Senate Rules Committee, Senate Floor Analysis, SB 1383 (August 31, 2016) at 4, https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201520160SB1383#; *see also* Assembly Committee on Natural Resources, Senate Third Reading Analysis, SB 1383 (August 31, 2016), https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201520160SB1383#; Senate Committee on Environmental Quality, SB 1383 (August 31, 2016), https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201520160SB1383#; Assembly Committee on Natural Resources, SB 1383 (August 30, 2016), https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201520160SB1383#.

[152] Response, *supra* note 9, at 4.

[153] Petition, *supra* note 1, at 10; *see supra* section III.A.3.c.

[154] Petition, *supra* note 1, at 10; (quoting *Clean-air plan for San Joaquin Valley first to meet all federal standards for fine particle pollution*, CAL. AIR RES. BD. (Jan. 24, 2019), https://ww2.arb.ca.gov/news/clean-air-plan-san-joaquin-valley-first-meet-all-federal-standards-fine-particle-pollution).

[155] *Id.* (citing *Indicators Overview*, CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/indicators#:~:text=Sensitive%20population%20indicators%20measure%20the,of%20their%20age%20or%20health (last visited Mar. 25, 2022); *see* AM. LUNG ASSN., STATE OF THE AIR 2021 23, https://www.lung.org/getmedia/17c6cb6c-8a38-42a7-a3b0-6744011da370/sota-2021.pdf; Ashley E. Larsen et al., *Agricultural pesticide use and adverse birth outcomes in the San Joaquin Valley of California*, 6 NATURE COMMC'N 1, 4–8 (2007); Amy M. Padula et al., *Traffic-Related Air Pollution and Risk of Preterm Birth in the San Joaquin Valley of California*, 24 ANN EPIDEMIOL 1, 6–9; *see also* Robbin Marks, Nat. Res. Def. Council, *Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health* (2001), https://www.nrdc.org/sites/default/files/cesspools.pdf).

[156] *Id.* (citing Brendan Borrell, *California's Fertile Valley is Awash with Air Pollution*, MOTHER JONES (Dec. 10, 2018), https://www.motherjones.com/environment/2018/12/californias-fertile-valley-is-awash-in-air-pollution/; *see*

the San Joaquin Valley, which is occurring in response to the perverse incentives in the LCFS, makes local air quality *worse*, not better—especially for those who live near a dairy with a methane digester, and *particularly* for those who live near a dairy that produces and combusts the factory farm gas onsite.[157]

Second, dairy water pollution and consumption are sickening San Joaquin Valley residents. As noted above, domestic wells are already running dry in the San Joaquin Valley, and expansion and consolidation of dairies in this area is exacerbating the already severe water scarcity issues that residents face.[158] Moreover, as the Petition notes, what water resources remain in San Joaquin Valley communities are contaminated with nitrates, arsenic, and 1,2,3 TCP, among other things, and half of California's public water systems that serve unsafe drinking water are located in these communities.[159] Dairy nitrate loading has caused widespread nitrate pollution of drinking water sources, causing nitrate levels to exceed federal drinking water standards and exposing residents to severe illnesses such as Blue Baby Syndrome and cancer.[160] Nitrate levels exceed federal drinking water standards in 24 to 40% of domestic wells in San Joaquin Valley counties, compared to 10 to 15% of California's overall water supply.[161]

Accordingly, CARB is directly harming the residents of the San Joaquin Valley by administering the LCFS in such a way that makes air and other forms of pollution worse. This has a disparate impact on the basis of race and income, and CARB must immediately reform the LCFS to prevent these harms from continuing to intensify and compound.[162] CARB must act now and stop prioritizing industry interests in profit over the needs of residents of the San Joaquin Valley.

IV. CARB SHOULD SUSPEND PATHWAY CERTIFICATIONS PENDING A RULEMAKING.

CARB has the authority to pause pathway certifications pending a rulemaking to address the substantial issues raised in the Petition, including but not limited to over-valued credits and non-additional credits that are undermining the market and leading to racially disparate impacts in California. CARB has this authority for three primary reasons. First, CARB has no duty to process and approve pathway certifications by a date certain. Second, CARB's interpretation of its "well to wheel" system boundary for biomethane from dairy and swine manure is a matter of agency interpretation and neither codified in the LCFS regulations nor the governing statutory scheme. Third, and most importantly, CARB has an affirmative duty to ensure its programs and

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also Policies and Procedures for Poor Outdoor Air Quality Days, SJVAPCD, http://www.valleyair.org/programs/ActiveIndoorRecess/intro.htm (last visited Mar. 25, 2022).

[157] *See supra* sections III.A.2; III.A.3.

[158] *See supra* section III.A.3.b.

[159] *See* Petition, *supra* note 1, at 9 (citing Del Real, J.A., *They Grow the Nation's Food, but They Can't Drink the Water*, N.Y. TIMES (May 21, 2019), https://www.nytimes.com/2019/05/21/us/california-central-valley-tainted-water.html).

[160] *See supra* section III.A.3.a; Petition, *supra* note 1, at 29–30.

[161] *See* Petition, *supra* note 1, at 9 (citing Eli Moore, et al., *The Human Costs of Nitrate-contaminated Drinking Water in the San Joaquin Valley*, PAC. INST., 11 (2011), https://pacinst.org/publication/human-costs-of-nitrate-contaminated-drinking-water-in-the-san-joaquin- valley/).

[162] *See* Petition, *supra* note 1, at 8–9 (noting that San Joaquin Valley residents are disproportionately low-income and Latino/a/e as compared to California as a whole); *supra* section III.A.3; *infra* section IV.C.

policies comply with both AB 32 and civil rights laws, including Government Code § 11135 and Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d. Thus, CARB may not simply defer consideration of the Petition until some discretionary future date while allowing further deterioration of the LCFS market and racial discrimination.

A. The LCFS regulations governing the pathway certification process impose no duty on CARB to approve Tier 1 or Tier 2 applications on a specific timeline and give CARB authority to modify its implementation of factory farm gas credit certification.

The regulations for processing LCFS credit applications provide CARB authority to decide when and whether to grant applications and include the authority to modify or delete *any* determination related to factory farm gas credit generation. This authority has two aspects. First, the Executive Officer has discretion to pause application processes for Tier 1 and Tier 2 pathway certifications according to its LCFS regulations codified at 17 Cal. Code of Regs. §§ 95488.6 and 95488.7. Neither provision compels the Executive Officer to certify an application by any date. Neither provision establishes timetables for the Executive Officer's review and processing of applications, including the Executive Officer's assessment and determination of whether a Tier 2 applicant's response to public comments is "adequate."[163] The provisions give the Executive Officer authority to request additional information and give the Executive Officer the discretion to certify or reject a pathway application.[164] The Executive Officer also has no obligation to even consider Provisional pathway applications (*i.e.*, facilities without the requisite 24 months of operational data to support the application).[165]

Second, the Executive Officer has authority to modify or delete any determination related to the generation of credits from factory farm gas. Section 95488.9 governs the special circumstances for fuel pathway applications, including the carbon intensity of factory farm gas. "[A] fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion *may* be certified with a CI that reflects the reduction of greenhouse gas emissions" provided that the captured methane "otherwise would have been vented to the atmosphere" and the avoided methane "is additional to any legal requirement."[166]

This authority to certify LCFS credits for factory farm gas has an important parallel provision which authorizes the Executive Officer to modify or delete any determination made pursuant to this section. Section 95495 provides extremely broad authority to the Executive Officer to "modify or delete a Certified CI." The regulation defines "Certified CI" to mean "*any* determination relating to carbon intensity made pursuant to sections 95488 through 95488.10."[167] Furthermore, the section authorizes modification or deletion of a Certified CI

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[163] 17 Cal. Code of Regs. § 95488.7(d)(5)(B).
[164] 17 Cal. Code of Regs. §§ 95488.6(b), 95488.7(d).
[165] 17 Cal. Code of Regs. § 95488.9(c) ("Executive Officer *may* consider Provisional pathway applications" (emphasis added)). CARB has approved at least one provisional application since the factory farm gas petition was filed on October 27, 2021.
[166] 17 Cal. Code of Regs. § 95488.9(f)(1), (f)(1)(A), (f)(1)(B) (emphasis added).
[167] 17 Cal. Code of Regs. § 95495(a) (emphasis added).

when "[a]ny of the information used to generate or support the Certified CI was incorrect[.]"[168] This broad modification and deletion provision thus allows the Executive Officer to correct its implementation of the provision authorizing factory farm gas credit generation, section 95488.9.

Taken together, the Executive Officer has ample authority to refrain from making the numerous determinations on pending or incoming Tier 1 and Tier 2 pathway certifications while it considers the issues raised by the Petitioners and several CARB members regarding factory farm gas in the LCFS.[169] The Executive Officer is not bound to act with haste on such applications. At the same time, the Executive Officer also has authority to modify or delete any determination relating to the carbon intensity of factory farm gas. The Executive Officer's assessment and approval of pathway applications require the agency to analyze the application in multiple ways to inform its judgement when making the decisions leading to certification or modification.

B. CARB's well to wheels interpretation for biomethane from dairy and pig manure is a matter of agency interpretation and not codified.

The carbon intensity determinations that CARB has authority to modify or delete under 17 Cal. Code Regs. § 95495 are the product of its own interpretation of the "well-to-wheels" life cycle analysis for factory farm gas. The LCFS requires a full "well-to-wheels" life cycle analysis to account for all emissions associated with a given fuel.[170] That carbon intensity is based on CARB's narrow interpretation of the life cycle of biomethane fuels from dairy and pig manure that exclude emissions upstream and downstream of the liquefied manure lagoon. For a Tier 1 application, the applicant uses the "Simplified Calculator" to input various parameters to determine the carbon intensity.[171] Such well-to-wheels accounting requires Tier 2 pathways to include "a description of all fuel production feedstocks used, including all pre-processing to which feedstocks are subject."[172] Likewise, applicants must provide:

> a detailed description of the calculation of the pathway CI. This description must provide clear, detailed, and quantitative information on process inputs and outputs, energy consumption, greenhouse gas emissions generation, and the final pathway carbon intensity, as calculated using CA-GREET3.0. Important intermediate values in each of the primary life cycle stages shall be shown. *Those stages include but are not limited to feedstock production and transport*; fuel

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[168] 17 Cal. Code of Regs. § 95495(b)(1)(A).
[169] *See January 27, 2022, Board Meeting Agenda*, CAL. AIR RES. BD., Agenda Item 4 (Board member discussion begins at 3:29), https://cal-span.org/unipage/?site=cal-span&owner=CARB&date=2022-01-27.
[170] 17 Cal. Code of Regs. § 95481(a)(66).
[171] *See* 17 Cal. Code of Regs. §§ 95488.6(a)(1); Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure, https://www.arb.ca.gov/fuels/lcfs/ca-greet/tier1-dsm-calculator-corrected.xlsm?_ga=2.79602192.588832615.1643761833-1197463774.1634834889; Tier 1 Simplified CI Calculator Instruction Manual Biomethane from Anaerobic Digestion of Dairy and Swine Manure, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.87401756.588832615.1643761833-1197463774.1634834889.
[172] 17 Cal. Code of Regs. § 95488.7(a)(2)(A)(2).

> production, fuel transport, and dispensing; co-product production, transport and use; waste generation, treatment and disposal; and fuel use in a vehicle.[173]

Nothing in AB 32 or the LCFS regulations compel the narrow well-to-wheels system boundary applied to factory farm gas projects. CARB appears to ground its interpretation on the system boundary described in the cap and trade Compliance Offset Protocol Livestock Projects, which represents an uncodified agency interpretation and not compelled by the Legislature.[174]

C. CARB has a duty to ensure its policies and programs comply with AB 32 and civil rights laws.

Setting aside the fact that CARB has the authority to pause Tier 1 and Tier 2 pathway certifications and modify or delete the Certified CI (which includes any determination with respect to factory farm gas fuels), CARB has the *affirmative duty* to ensure that its policies and programs comply with AB 32 and civil rights laws. This affirmative duty compels CARB to pause factory farm gas pathway certifications while it considers amendments to the LCFS to address the significant issues raised in the petition because to do otherwise risks continued violation of California and federal law.

First, AB 32 directs CARB to ensure that the LCFS represents the maximum cost-effective, technologically feasible reductions and does not disproportionately impact low-income communities.[175] AB 32 also directs CARB to ensure that LCFS credits are additional.[176] These provisions do not allow CARB to continue implementing the LCFS without regard to the substantial issues raised by the petition that indicate CARB's widespread certification of over-valued and illusory, non-additional credits is distorting and undermining the LCFS program. Second, California law prohibits CARB from adopting and implementing the LCFS in a manner that subjects people to discrimination. Government Code § 11135 states:

> No person in the State of California shall, on the basis of sex, race, color, religion, ancestry, national origin, ethnic group identification, age, mental disability, physical disability, medical condition, genetic information, marital status, or sexual orientation, be unlawfully denied full and equal access to the benefits of, or be

[173] 17 Cal. Code of Regs. § 95488.7(a)(2)(B) (emphasis added).
[174] *See* Livestock Protocol, *supra* note 36, section 1.1(b) and Table 4.1, Description of all GHG Sources, GHG Sinks, and GHG Reservoirs; *see also* CAL. AIR RES. BD., RESPONSE TO ANIMAL DEFENSE LEGAL FUND COMMENT, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/new_temp_carb_response.pdf (CARB arguing that "Emissions from existing CAFO operations are accounted for, but do not include emissions associated with enteric methane and animal feed use because these emissions should more appropriately be allocated to and associated with the preexisting underlying, non-fuel product stream, and are thus excluded from the system boundary in the Board approved Tier 1 Calculator."). Table 4.1 of the Compliance Offset Protocol Livestock Projects also shows that nitrous oxide from digestate composting and storage is specifically excluded in downstream emissions. This particular downstream exclusion has a significant impact on the CI determination. A 2017 study which CARB does not dispute found that composting of digested manure solids released such significant nitrous oxide emissions relative to undigested manure solids that the climate benefits of the captured methane from the digestion process *were cancelled out*. *See* Holly et al., *supra* note 41, at 410, 414, 418.
[175] Health & Safety Code §§ 38560.5(c), 38562(a) & (b)(2).
[176] § 38562(d)(2).

> unlawfully subjected to discrimination under, any program or activity that is conducted, operated, or administered by the state or by any state agency, is funded directly by the state, or receives any financial assistance from the state.

CARB has a similar duty under federal law because it receives federal financial assistance. Section 601 of the Civil Rights Act provides that no person shall, "on the ground of race, color, or national origin, be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity" covered by Title VI.[177] Not only does CARB have authority to stop granting pathway certifications for over-valued and non-additional credits, correct its interpretation underlying the certified CI determinations, and critically reassess the environmental justice implications of incentivizing factory farm pollution—CARB has *the obligation* to do so to prevent discrimination.

V. CONCLUSION

For the foregoing reasons, CARB should reconsider and grant the Petition. In addition, CARB must grant the requested interim relief by suspending certification of pathways for factory farm gas pending rulemaking to address the serious deficiencies in the LCFS. To do otherwise would undermine the goals and purpose of AB 32, devastate our land, air, water, and climate, allow oil companies to pollute more with inflated and illusory credits, and exacerbate disparate impacts in San Joaquin Valley communities already harmed by air and water pollution.

Respectfully submitted March 25, 2022,

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[177] 42 U.S.C. § 2000d.

Attach. 1

BEFORE THE CALIFORNIA AIR RESOURCES BOARD

PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM

PETITION FOR RULEMAKING

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I. INTRODUCTION

The California Air Resources Board (CARB) allows inflated and non-additional credits derived from factory farm gas[1] to undermine the integrity of the Low Carbon Fuel Standard (LCFS) pollution trading scheme and exacerbate discriminatory environmental and public health harms in the San Joaquin Valley. The LCFS increases harmful pollution to air, water, and land in rural low-income and Latina/o/e communities; inflates factory farm gas reductions by excluding upstream and downstream emissions; allows non-additional reductions from other factory farm gas incentive programs to generate credits; fails to achieve reductions from transportation fuels when these inflated and non-additional factory farm credits justify excessive fossil fuel emissions; and perversely incentivizes increased greenhouse gas emissions and pollution from dairy and pig factory farms.

To remedy these deficiencies, the Association of Irritated Residents (AIR), Leadership Counsel for Justice & Accountability, Food & Water Watch, and Animal Legal Defense Fund petition the CARB for rulemaking to amend the LCFS to exclude all fuels derived from factory farm gas. In the alternative, CARB must reform the LCFS program to account for the full life cycle of factory farm gas emissions – including all upstream and downstream emissions from activities and inputs at dairy and pig facilities – and exclude non-additional emissions reductions that occur as a result of other factory farm gas incentives, including the Dairy Digester Research Development Program. CARB must also take steps to ensure that its policies and practices do not impose discriminatory harms on low-income and Latina/o/e communities in the San Joaquin Valley.

In 2006, the California Legislature determined that climate change posed "a serious threat to the economic well-being, public health, natural resources, and the environment of California."[2] To address these threats, CARB designed a range of programs that would monitor, regulate, and ultimately reduce greenhouse gas emissions, including the LCFS.[3] But as written and as implemented, the LCFS pathways for factory farm gas do not effectively reduce greenhouse gas emissions, violating CARB's obligation to achieve the maximum cost-effective and technologically feasible emissions reductions.

The LCFS intentionally promotes factory farm gas, a fusion of Big Ag and Big Oil & Gas, two of the industries most responsible for the climate crisis and whose entire business model relies on extraction and exploitation. Big Ag brought us polluted wells, foul air, antibiotic-resistant pathogens, methane-spewing manure lagoons, and workplace conditions that caused rampant outbreaks of COVID-19. Big Ag has driven family farmers off their farms, stripped wealth from our communities, and gutted our rural main streets. Big Oil & Gas brought us countless oil spills, tanker wrecks, pipeline explosions, and climate damage. There is no reason to entrust our future to the very industries responsible for the harms the LCFS seeks to address.

[1] Factory farm gas refers to the fuel the LCFS designates "biomethane from the anaerobic digestion of dairy and swine manure."
[2] CAL. HEALTH & SAFETY CODE § 38501.
[3] CAL. HEALTH & SAFETY CODE § 38510.

The results of CARB's embrace of these false solutions to the benefit of Big Ag and Big Oil & Gas are clear: due to the LCFS's deficient accounting of the emissions from factory farm gas, the program encourages increased production of the liquified manure necessary to generate factory farm gas, resulting in *more* intentionally created methane from new and expanding dairy and pig facilities. By propping up factory farm gas, the LCFS provides a new way for big corporations to get rich off a problem they created. In CARB's accounting of the carbon intensity of factory farm gas, the LCFS fails to include the full quantity of associated upstream and downstream greenhouse gas emissions, leading to an exaggerated negative carbon intensity value and a corresponding inflation of LCFS credit prices for factory farm gas. The resulting inflated credits do not encourage emissions reductions, instead, they reward factory farms for the production of toxic manure as though it were a cash crop. This "hot air" in the credit market, along with the award of credits for reductions from other incentive programs that would have occurred anyway, undermines the LCFS framework by allowing transportation fuel producers to emit more climate pollution based on illusory reductions.

No amount of corporate public relations spin, greenwashing, or deficient carbon intensity calculations can hide the fact that factory farm gas is created from massive harm. By incentivizing increased manure production and liquification, the LCFS program also fails to maximize additional environmental benefits in violation of the *Global Warming Solutions Act of 2006* (AB 32), and even increases the well-documented environmental and public health harms caused by pig and dairy factory farms. These facilities release enormous quantities of solid, liquid, and gaseous waste. In addition to greenhouse gas emissions, the waste from both pigs and dairy cows releases various co-pollutants including ammonia, hydrogen sulfide, volatile organic compounds (VOCs), and severe odor. The factory farm system relies on disposing the manure nitrogen on crops, which also leads to both nitrous oxide emissions and nitrate contamination of groundwater. Experience tells us that racism, exploitation, and extraction are embedded in the factory farm system – we know these harms are disproportionately imposed on Black, Indigenous, People of Color, and low-income communities around the country. In California, these harms discriminatorily impact low-income and Latina/o/e communities in the San Joaquin Valley in violation of state and federal law.[4]

CARB has an affirmative duty under Government Code section 11135 (CA 11135) and Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d, to ensure that its policies and practices do not have a discriminatory impact on the basis of race.[5] CARB has an affirmative duty under AB 32 to ensure that "activities undertaken to comply with the regulations do not disproportionately impact low-income communities" and to design regulations in a manner that is equitable.[6] Finally, Government Code section 12955 (CA 12955) prohibits any practice or program that has a discriminatory effect on members of protected classes with respect to housing opportunities, including with respect to the use and enjoyment of dwellings.[7] Furthermore, the

[4] Addressing discriminatory impacts resulting from the LCFS's inclusion of factory farm gas in other parts of the country where dairy and pig factory farms are concentrated is beyond the scope of this petition. However, CARB should also evaluate these potential impacts, given that the program includes applicants from around the country. CAL. AIR RES. BD., *LCFS Pathways Requiring Public Comments*, https://ww2.arb.ca.gov/resources/documents/lcfs-pathways-requiring-public-comments#t2.

[5] CAL. GOV'T CODE § 11135; 42 U.S.C. § 2000d.

[6] CAL. HEALTH & SAFETY CODE § 38562(b).

[7] CAL. GOV'T CODE § 12955.8; CAL. CODE REGS. TIT. 2 § 12161.

accountability our democracy depends on the public knowing the truth: who is benefiting, where the money is coming from, who is defining the problem, who is being impacted, and how they are harmed by the LCFS. By failing to even conduct a transparent disparity analysis of this highly-technical program, CARB impedes the public's ability to fairly evaluate CARB's choice to prop up Big Ag and Big Oil & Gas.

A people's government – our government – protects and serves the people's interests. It invests in food and climate solutions that create a healthy future for our children and grandchildren. It invests in good jobs that strengthen our rural communities. But CARB has created and implemented a pollution trading scheme that benefits polluters rather than uses the power granted by the people of California to prevent harms. On top of decades of discriminatory impacts in the San Joaquin Valley, California is facing the dire impacts of the climate crisis. We cannot afford a scheme that serves corporate interests over the people's needs.

To remedy these harms and to bring the LCFS regulation into compliance with state and federal law, the petitioners request that CARB amend section 95488.9 of the LCFS to exclude any "fuel pathway that utilizes biomethane from dairy and swine manure digestion."[8] In the alternative, petitioners request that CARB amend the LCFS regulation to (a) ensure that the life cycle analysis for biomethane from dairy and swine manure is expanded to include a full accounting of life cycle emissions; (b) amend section 95488.9 to ensure additionality of reductions; (c) properly classify methane from swine and dairy factory farms as intentionally occurring; (d) ensure compliance with state and federal civil rights law, including but not limited to conducting disparity analyses of LCFS pathways and credit trading; and (e) ensure the LCFS provides environmental benefits and does not degrade water quality and interfere with efforts to improve air quality in the San Joaquin Valley.

II. BACKGROUND

A. THE LCFS PROGRAM

AB 32 set a statewide target to reduce California's greenhouse gas emissions to 1990 levels by 2020.[9] In 2007, Governor Arnold Schwarzenegger issued Executive Order S-01-07, which directed CARB to adopt the LCFS pollution trading scheme to diversify California's transportation fuels and curb dependence on petroleum.[10] The California Office of Administrative Law approved the LCFS regulation in 2010 and the regulation has since undergone four rounds of amendments.[11]

According to CARB, "[T]he LCFS is designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce

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[8] CAL. CODE REGS. TIT. 17 § 95488.9.
[9] CAL. HEALTH & SAFETY CODE § 38550.
[10] CAL. EXEC. DEP'T, Exec. Order No. S-01-07, (Jan. 22, 2007), *available at* https://www.library.ca.gov/Content/pdf/GovernmentPublications/executive-order-proclamation/5107-5108.pdf; *see also generally,* CAL. HEALTH & SAFETY CODE § 38560.5 (requiring CARB to establish GHG reduction measures).
[11] CAL. CODE REGS. TIT. 17 § 95480 et seq.

greenhouse gas emissions and decrease petroleum dependence in the transportation sector."[12] The LCFS, like similar pollution trading schemes, constructs a market where credits and deficits that represent emissions in relation to a declining baseline can be traded. These tradeable LCFS credits provide a new revenue stream for producers of fuels that have been deemed low-carbon intensity with the goal of incentivizing increased production and displacing the use of more greenhouse gas-intensive fuels. The LCFS requires entities that produce conventional transportation fuels to report the carbon intensity of these fuels, while certain alternative fuel producers may opt into the program and demonstrate their fuel's carbon intensity in their application.[13]

Every year, CARB sets progressively lower benchmarks for the carbon intensity of fuels.[14] Transportation fuels with carbon intensity values above the annual benchmark generate deficits, and transportation fuels with carbon intensity values below the benchmark generate credits (see Figure 1, Appendix C).[15] While obligated parties are required to either meet the benchmark or purchase credits to offset the extra emissions associated with their fuel, voluntary parties that produce alternative, low-CI fuels are incentivized to participate because fuels with carbon intensities below the benchmark generate revenue through the sale of LCFS credits.[16]

The LCFS regulation defines "carbon intensity" as "the quantity of life cycle greenhouse gas emissions, per unit of fuel energy, expressed in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ)."[17] The emissions included in each fuel's carbon intensity calculation are usually bounded by "fuel pathways," defined as "the collective set of processes, operations, parameters, conditions, locations, and technologies throughout all stages that CARB considers appropriate to account for in the system boundary of a complete well-to-wheel analysis of [a given] fuel's life cycle greenhouse gas emissions."[18] Accurate and thorough life cycle analyses for each fuel and the accurate accounting of the baseline against which each fuel's carbon intensity is compared are independent and necessary preconditions for the program to identify which fuels to encourage to decrease net greenhouse gas emissions.

The LCFS classifies fuel pathways into three groups: Lookup Table, Tier 1, and Tier 2 pathways.[19] Regulated parties can register their fuels using the standard pathways in the Lookup

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[12] *Low Carbon Fuel Standard: About,* CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Oct. 12, 2021).
[13] CAL. CODE REGS. TIT. 17 §§ 95483-95483.1.
[14] CAL. CODE REGS. TIT. 17 § 95484.
[15] *Id.*
[16] CARB accounts for credits and implements credit transfers with the LCFS Reporting Tool and Credit Bank & Transfer System. CAL. AIR RES. BD., *LCFS Registration and Reporting*, https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-registration-and-reporting (last visited Oct. 12, 2021).
[17] CAL. CODE REGS. TIT. 17 § 95481(a)(26). "Life Cycle Greenhouse Gas Emissions," in turn, is defined as "the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions, such as significant emissions from land use changes) as determined by the Executive Officer, related to the full fuel life cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential. CAL. CODE REGS. TIT. 17 § 95481(a)(88).
[18] CAL. CODE REGS. TIT. 17 § 95481(a)(66).
[19] CAL. CODE REGS. TIT. 17 § 95488.1(a).

Table if the fuel produced "closely corresponds" to a Lookup Table pathway.[20] Tier 1 and Tier 2 pathways are open to voluntary applicants, including those seeking credit for factory farm gas. Tier 1 is for "the most common low carbon fuels" and uses a Simplified CI calculator, where Tier 2 is for "innovative, next generation fuel pathways," and uses the full CA-GREET3.0 model.[21] Tier 1 includes fuels like ethanol and biomethane anaerobic digesters of dairy and swine manure, among others.[22] Tier 2 includes fuels from sources not in Tier 1 as well as pathways included in Tier 1 that use "innovative production methods."[23] The majority of factory farm gas producers apply for Tier 2 pathways rather than the Tier 1 pathway.

Ten years after enacting AB 32, the California Legislature set a new target for greenhouse gas emissions in Senate Bill 32 (SB 32) – 40 percent below 1990 levels.[24] The Legislature stipulated, however, that SB 32 would only be operative if it also enacted Assembly Bill 197 (AB 197), which amended AB 32 in several ways.[25] AB 197 added Section 38562.5, which required that regulations promulgated to achieve emissions reductions beyond the statewide greenhouse gas limit, including the LCFS, consider the social costs of greenhouse gases, prioritize direct emissions reductions, and incorporate the requirements of Section 38562(b).[26] These requirements include crucial mandates to design the regulations in a manner that is equitable; ensure that activities taken to comply with the regulations "do not disproportionately impact low-income communities" and "do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions;" and consider the overall societal benefits, including reductions in other air pollutants and other benefits to the environment.[27]

B. THE SAN JOAQUIN VALLEY

California's San Joaquin Valley, as discussed in this petition, refers to eight counties that compose the valley floor from San Joaquin County in the north, to Kern County in the south. While disadvantaged communities within the region confront air pollution, toxic emissions, and unsafe drinking water at rates and degrees disproportionate to other communities in the state, the San Joaquin Valley is also home to resilient, diverse communities and networks that have worked together over decades to promote robust mutual aid networks, expand civic engagement, and lead

[20] CAL. CODE REGS. TIT. 17 § 95488.5(a)(1)-(6) ("Closely corresponds" means that the applicant's fuel pathway and a pathway on the Lookup Table are consistent in feedstock, production technology, the region in which the feedstock and fuel is produced, transport distance (if applicable), types and amount of thermal and electrical energy used in feedstock and finished fuel production, and that the CI of the entity's product is lower than or equal to the CI of the pathway in the lookup table.)

[21] CAL. AIR RES. BD., LCFS Guidance 19-01, Book and Claim Accounting for Low-CI Electricity 2, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-01.pdf. While Tier 1 applicants provide a "discrete set of inputs" based on the specifics of their operations to be used by one of the pre-existing Tier 1 Simplified CI Calculators, Tier 2 applicants must conduct and submit a full life cycle analysis using the CA-GREET3.0 model for their own customized pathway. CAL. CODE REGS. TIT. 17 § 95488.3.

[22] CAL. CODE REGS. TIT. 17 § 95488.1(c).

[23] CAL. CODE REGS. TIT. 17 § 95488.1(d).

[24] CAL. HEALTH & SAFETY CODE § 38566.

[25] SB 32, 2016 CAL. LEGIS. SERV. CH. 249.

[26] AB 197, 2016 CAL. LEGIS. SERV. CH. 250.

[27] CAL. HEALTH & SAFETY CODE §§ 38562(2), (4), (6).

efforts from the household to the community level to model climate resilience and environmental stewardship.

The region is known for and, to a great extent, characterized by industrial agricultural operations, including large confined animal feeding operations. Decades of similar investment, land use, and economic development strategies have failed and continue to fail to prioritize the economic well-being and health of San Joaquin Valley residents, leading to severe income inequality, poverty, and environmental degradation despite the inherent assets of the region.

The "disadvantaged communities" of California, as defined pursuant to Senate Bill 535, are concentrated in the San Joaquin Valley.[28] Seven of the eight counties in the Valley (all except San Joaquin County) report mean income well below the 120% limit that defines low-income.[29] Every county in the San Joaquin Valley has lower household and per capita incomes, and higher poverty rates than California as a whole.[30] While median household income in California in 2019 was $75,235, countywide household median incomes for San Joaquin Valley Counties ranged from $49,687 to $64,432. The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $53,672 and $49.687 – both at 71 percent or below statewide median income.[31] Notably, nine of ten of the most recent applications for consideration for Low Carbon Fuel Standard Tier 2 Pathways from California factory farm gas were in Tulare County and Kern County. Kern County, like Merced and Tulare, faces disproportionately high poverty rates at 19 percent. Even this data likely inflates reported income level, because it may exclude the San Joaquin Valley's thousands of undocumented residents and residents of the Valley's unincorporated communities.[32]

San Joaquin Valley residents are disproportionately Latina/o/e as compared to California as a whole. All eight San Joaquin Valley Counties have higher Latino populations than the state,[33] with populations ranging from 42 percent to 65.6 percent, as compared to the state population with

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[28] CAL. ENV'T PROT. AGENCY, *Designation of Disadvantaged Communities Pursuant to Senate Bill 535 (De León)* 1-32 (Apr. 2017), https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf.
[29] Section 39711 of the Health and Safety Code sets the ceiling for low-income communities at 120% of the area median income. Additionally, Section 39711 designates communities with disproportionate environmental impacts and concentrations of low income, high unemployment, low educational attainment, and other burdensome socioeconomic factors as disadvantaged communities. All eight counties of the San Joaquin Valley fall within these categories. *See Maps & Data,* CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Apr. 9, 2021) (flagging areas of California that exhibit high to low pollution burdening scores). *Income Limits*, U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il.html#2020_data (last updated Apr. 1, 2020) (choose 30% Income Limit for ALL Areas (Excel)); *FY 2020 State Income Limits* (2020), U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il/il20/State-Incomelimits-Report-FY20r.pdf.
[30] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).
[31] Poverty rates in every single county in the San Joaquin Valley also exceed poverty rates in California, with Merced, Tulare facing 17 and 18.9 percent poverty rates (as compared to 11.8 percent at the statewide level). *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).
[32] 310,000 people live in low-income unincorporated communities in the San Joaquin Valley – "this is 70,000 more than what the Census Bureau included in its low-income Census Designated Places in the San Joaquin Valley." POLICYLINK, *California Unincorporated: Mapping Disadvantaged Communities in the San Joaquin Valley* 9 (2013), https://www.policylink.org/sites/default/files/CA%20UNINCORPORATED_FINAL.pdf.
[33] Latino is the term used by the U.S. Census.

39.4 percent of residents classified as Latino. At least seven of eight San Joaquin Valley communities have a lower proportion of white residents as compared to the state as a whole.[34] Merced and Tulare counties have white, non-Latino populations of 26.5 and 27.7 percent, and Latino populations of 65.6 and 61 percent, respectively.[35] Like Merced and Tulare, Kern County also demonstrates much higher Latino populations than the rest of the state, with a Latino population of 54.6 percent.

The disproportionately low-income and Latina/o/e residents of the San Joaquin Valley are exposed to the worst air quality in the state by most measures and lower income communities in the San Joaquin Valley are disproportionately subject to water contaminated with nitrates, arsenic, and 1,2,3 TCP, among others. The San Joaquin Valley is classified as an area that fails to meet several federal health-based standards for fine particulate matter ($PM_{2.5}$).[36] According to the American Lung Association, the San Joaquin Valley cities of Fresno-Madera-Hanford and Bakersfield are the second and third most polluted with respect to short-term exposure to $PM_{2.5}$.[37] The Valley cities of Bakersfield, Fresno-Madera-Hanford, and Visalia are the first, second, and third most polluted with respect to long-term exposure to $PM_{2.5}$.[38] The Valley also violates health-based standards for ozone.[39] Bakersfield, Visalia, and Fresno-Madera-Hanford are the second, third, and fourth most ozone-polluted cities in the in United States.[40] The San Joaquin Valley contains about half of California's 300 public water systems that currently serve unsafe drinking water.[41] Over the past three decades, nitrate levels in drinking water have exceeded the federal maximum contaminant level of 45 mg/L NO_3 (equivalent to 10 mg/L nitrate-N) in an estimated 24 to 40% of domestic wells in different counties in the San Joaquin Valley, compared to 10 to 15% of California's overall water supply.[42]

This pollution impacts the health and well-being of San Joaquin Valley residents.[43] Short-term exposure to $PM_{2.5}$ pollution causes premature death, decreased lung function, exacerbates respiratory disease such as asthma, and causes increased hospital admissions.[44] Long-term

[34] According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[35] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[36] 80 FED. REG. 18,528 (April 7, 2015); 81 FED. REG. 2,993 (January 20, 2016); 80 FED. REG. 2,206, 2,217 (January 15, 2015).

[37] AM. LUNG ASSN., *State of the Air 2021* 37, *available at* https://www.lung.org/getmedia/17c6cb6c-8a38-42a7-a3b0-6744011da370/sota-2021.pdf.

38 *Id.* at 38.

[39] 75 FED. REG. 24409 (May 5, 2010); 77 FED. REG. 30088, 30092 (May 21, 2012).

[40] AM. LUNG ASSN., *supra* note 37 at 36.

[41] Del Real, J.A., *They Grow the Nation's Food, but They Can't Drink the Water*, N.Y. TIMES (May 21, 2019), https://www.nytimes.com/2019/05/21/us/california-central-valley-tainted-water.html.

[42] Eli Moore, et al., *The Human Costs of Nitrate-contaminated Drinking Water in the San Joaquin Valley*, PAC. INST., 11 (2011), https://pacinst.org/publication/human-costs-of-nitrate-contaminated-drinking-water-in-the-san-joaquin-valley/.

[43] The COVID-19 pandemic has made exposure to particulate matter even more dangerous, further highlighting the health risks associated with air pollution from factory farm dairies and factory farm gas. Xiao Wu et al., *Air pollution and COVID-19 mortality in the United States: Strengths and limitations of an ecological regression analysis*, 6 SCI. ADVANCES 1 at 1-2 (Nov. 4, 2020), https://advances.sciencemag.org/content/6/45/eabd4049.

[44] AM. LUNG ASSN., *supra* note 37 at 37-38.

exposure can cause asthma and decreased lung function in children, increased risk of death from cardiovascular disease, and increased risk of death from heart attacks.[45] Nitrates in drinking water can cause serious illness and death in infants ("blue baby syndrome") and are linked to pregnancy complications and birth defects, Sudden Infant Death Syndrome, and respiratory tract infections and a number of different cancers in adults and children.[46]

CARB has acknowledged that $PM_{2.5}$ exposure alone "is responsible for about 1,200 cases of premature death in the Valley each year."[47] San Joaquin Valley residents, who CalEnviroScreen designate a "sensitive population," experience higher rates of asthma, low birth weight, and cardiovascular disease compared to state incidence rates.[48] The California Institute for Rural Studies estimates that the costs of these air quality-related health harms total over $6 billion per year in the San Joaquin Valley.[49] This pollution also impacts residents' quality of life. For example, children in the San Joaquin Valley suffer from lack of access to outdoor recreation – on days with especially poor air quality, which occurred 40 days in Kern County in 2018, local authorities recommend that schools hold recess indoors.[50]

III. CARB MUST EXCLUDE BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LCFS OR IN THE ALTERNATIVE AMEND THE REGULATION TO ACCURATELY ACCOUNT FOR THE FULL CARBON INTENSITY OF THESE FUELS AND PROHIBIT CREDITS FROM NON-ADDITIONAL REDUCTIONS.

The LCFS violates sections 38560.5, 38562(b), 38562(d)(2), 38562.5 of the Health & Safety Code because it fails to achieve the maximum technologically feasible and cost-effective emissions reductions, fails to maximize additional environmental benefits, fails to ensure additionality of reductions, and exacerbates harms associated with industrial animal agriculture, including toxic air contaminants and dangerous water pollution. These failures prevent the state from maximizing greenhouse gas emissions reductions from transportation fuels and constitute a failure to use best scientific practices, as required by section 38562(e). Moreover, they harm San

[45] *Id*. at 38-39.
[46] WIS. DEP'T OF HEALTH SERV., *Infant Methemoglobinemia (Blue Baby Syndrome)*, https://www.dhs.wisconsin.gov/water/blue-baby-syndrome.htm (last updated Mar. 12, 2021).
[47] CAL. AIR RES. BD., *Clean-air plan for San Joaquin Valley first to meet all federal standards for fine particle pollution* (Jan. 24, 2019), https://ww2.arb.ca.gov/news/clean-air-plan-san-joaquin-valley-first-meet-all-federal-standards-fine-particle-pollution.
[48] *Indicators Overview*, CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/indicators#:~:text=Sensitive%20population%20indicators%20measure%20the,of%20their%20age%20or%20health (last visited Oct. 21, 2021); *see* AM. LUNG ASSN., *supra* note 37 at 23; Ashley E. Larsen et al., *Agricultural pesticide use and adverse birth outcomes in the San Joaquin Valley of California*, 6 NATURE COMMC'N 1, AT 4-8 (2007); Amy M. Padula et al., *Traffic-Related Air Pollution and Risk of Preterm Birth in the San Joaquin Valley of California*, 24(12) ANN EPIDEMIOL 1, 6-9; *see also* Robbin Marks, Nat. Res. Def. Council, *Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health* (2001), https://www.nrdc.org/sites/default/files/cesspools.pdf.
[49] Lisa Kresge and Ron Strochlic, *Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health*, CAL. INST. FOR RURAL STUDIES 8, (Jul. 2007).
[50] Brendan Borrell, *California's Fertile Valley is Awash with Air Pollution*, MOTHERJONES (Dec. 10, 2018), https://www.motherjones.com/environment/2018/12/californias-fertile-valley-is-awash-in-air-pollution/. *See also Policies and Procedures for Poor Outdoor Air Quality Days*, SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DIST., http://www.valleyair.org/programs/ActiveIndoorRecess/intro.htm (last visited Oct. 12, 2021).

Joaquin Valley communities with increased air and water pollution from factory farm dairies subsidized by the LCFS – harms the Legislature sought to address when it enacted AB 32 and AB 197.[51] For all of these reasons, CARB should amend the LCFS to exclude all fuels derived from biomethane from swine and dairy manure.[52] If CARB fails to do so, it must at a minimum amend the regulation to capture the full life cycle of associated greenhouse gas emissions in both the established Tier 1 pathway and the customized Tier 2 pathways and amend the regulation to ensure credited reductions are additional.[53]

A. The fuel pathways for biomethane from dairy and swine manure fail to achieve the maximum technologically feasible and cost-effective emissions reductions.

AB 32 mandates that the early action measure regulations adopted by CARB "shall achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit."[54] CARB explicitly premised the adoption of the LCFS regulation on this mandate.[55] As written and in practice, however, the LCFS regulation does not incentivize, let alone achieve, the maximum emissions reductions in this sector due to the program's inflation of carbon intensity values for factory farm gas. These inflated credit values are the result of CARB's narrow interpretation of the life cycle emissions for factory farm gas. Moreover, CARB's failure to ensure that credited emissions reductions are additional to what otherwise would have occurred inject invalid credits into the overall market and allow fuel producers to emit more pollution.

By setting overly narrow system boundaries for the life cycle analysis of factory farm gas, the LCFS fails to account for emissions associated with a true "well-to-wheels" analysis, exaggerating the emissions reductions attributed to this fuel. AB 32 requires that market-based compliance mechanisms only credit "additional" emissions reductions, and thus exclude reductions already required by law or that otherwise would occur.[56] However, CARB has allowed the LCFS program to award credits generated from non-additional reductions at factory farms. Factory farm gas projects rely on multiple sources of revenue from grant programs, federal programs, and the Aliso Canyon settlement – all of this supplementary revenue renders reductions from factory farm gas projects either partially or fully non-additional, yet CARB has made no effort to prevent these non-additional credits from entering the market.

Because CARB has allowed grossly inflated carbon intensity scores to distort the market, and allowed non-additional reductions to generate credits, the LCFS perversely incentivizes bigger dairy and pig operations to generate more methane. As a result, credit revenue from dairy factory

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[51] CAL. HEALTH & SAFETY CODE § 38501 (the Legislature named the "exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems" as potential adverse impacts of climate change.)
[52] CAL. CODE REGS. TIT. 17 § 95488.3; CAL. CODE REGS. TIT. 17 § 95488.9(f)(1). *See* proposed amendments in Appendix A.
[53] *See* proposed amendments in Appendix B.
[54] CAL. HEALTH & SAFETY CODE § 38560.5.
[55] CAL. AIR RES. BD., RES. 19-27, (Nov. 21, 2019).
[56] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

farm gas can be a more reliable income stream than milk revenue, propping up this high-emissions industry and further polluting nearby communities. Additionally, the financial windfall from these over-valued credits is traded to offset emissions from LCFS deficit holders. Together and separately, each of these violations undermines the LCFS program and constitutes a failure to achieve the maximum technologically feasible and cost-effective emissions reductions from transportation fuels in violation of AB 32.

1. The fuel pathways for biomethane from dairy and swine manure fail to incorporate life-cycle emissions, leading to inflated credits.

The LCFS over-values credits awarded to factory farm gas operations because the program omits significant emissions from the factory farm gas life cycle. Neither the established Tier 1 nor the customized Tier 2 pathways for biomethane from dairy and swine manure capture the greenhouse gas emissions associated with the full life cycle of factory farm gas. The pathways ignore both upstream and downstream emissions. In addition to setting overly narrow system boundaries, the factory farm gas life cycle analyses fail to properly account for the fact that the methane purportedly captured in the production of factory farm gas is intentionally created, resulting in an even more misleading accounting of associated climate harms. When the resulting inflated credits are traded, they allow LCFS deficit holders to achieve less than the required maximum technologically feasible and cost-effective reductions.

The LCFS requires a full "well-to-wheels" life cycle analysis to account for all emissions associated with a given fuel.[57] Such well-to-wheels accounting requires Tier 2 pathways to include "a description of all fuel production feedstocks used, including all pre-processing to which feedstocks are subject."[58] Likewise, applicants must provide:

> a detailed description of the calculation of the pathway CI. This description must provide clear, detailed, and quantitative information on process inputs and outputs, energy consumption, greenhouse gas emissions generation, and the final pathway carbon intensity, as calculated using CA-GREET3.0. Important intermediate values in each of the primary life cycle stages shall be shown. *Those stages include but are not limited to feedstock production and transport*; fuel production, fuel transport, and dispensing; co-product production, transport and use; waste generation, treatment and disposal; and fuel use in a vehicle.[59]

Feedstocks are the raw materials processed into fuel. The feedstock for factory farm gas is manure. Therefore, emissions from manure production and "pre-processing" must be included in the life cycle analysis for Tier 2 applicants. But the LCFS and CARB's implementation does not require their inclusion. For example, CalBioGas Kern Cluster's recent application begins the data-listing portion of its lifecycle analysis with the Dairy Livestock Input Data table.[60] This table does not provide an adequate analysis of the feedstock production energy input. In fact, this lifecycle

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[57] CAL. CODE REGS. TIT. 17 § 95481(a)(66).
[58] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(2).
[59] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(B) (emphasis added).
[60] CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

analysis contains no analysis pertaining to the emissions from the generation and processing of manure to produce the feedstock.

Accounting for the greenhouse gas emissions from the production and "pre-processing" of dairy or pig manure must include the inputs and infrastructure necessary to sustain a dairy cow or a pig: its food and water, the methane animals produce through enteric fermentation, the construction and maintenance of the lagoons required to hold manure, trucking livestock and other inputs, combustion of fuels at the dairy facility for electricity, and more. But the LCFS factory farm gas pathways only begin after the production of the manure itself, leaving out all upstream emissions generated formulating that manure.[61]

The regulation further enumerates that, "for fuels utilizing agricultural crops for feedstocks, the description [of feedstocks in the life cycle analysis report] shall include the agricultural practices used to produce those crops. This discussion shall cover energy and chemical use, typical crop yields, feedstock harvesting, transport modes and distances, storage, and pre-process (such as drying or oil extraction)."[62] In the Tier 2 pathways for ethanol production, this provision has been interpreted to include production and pre-processing of corn, the feedstock for ethanol. Similarly, the LCFS requires pathways that utilize organic material to "demonstrate that emissions are not significant beyond the system boundary of the fuel pathway," upon request.[63] Yet in the case of factory farm gas, none of the production and pre-processing of the feedstock is considered, making it an outlier in the LCFS program and out of compliance with section 95488.7.

The failure to include production and pre-processing of manure when calculating life cycle emissions is even more problematic because a common feed for dairy cows in California is distillers grains, a "co-product" of ethanol production. The designation of distillers grains as a "co-product" allows ethanol producers to split the emissions from corn production between the ethanol and distillers grains by weight, decreasing ethanol's carbon intensity in the LCFS analysis.[64] One ethanol industry blog noted that "the biggest factor for most of the low-CI scoring [ethanol] plants is the proportion of wet distillers grains sold locally."[65] Distillers grains are granted the "co-product" designation by virtue of the revenue they generate when sold as animal feed but because LCFS factory farm gas pathways do not account for production and pre-processing of manure, the emissions associated with distillers grains are never accounted for by the LCFS at all despite its

[61] CAL. AIR RES. BD., *Compliance Offset Protocol Livestock Projects* (Nov. 14, 2014), Table 4.1, Description of all GHG Sources, GHG Sinks, and GHG Reservoirs; *see also* CAL. AIR RES. BD., Response to Animal Defense Legal Fund Comment, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/new_temp_carb_response.pdf (CARB arguing that "Emissions from existing CAFO operations are accounted for, but do not include emissions associated with enteric methane and animal feed use because these emissions should more appropriately be allocated to and associated with the preexisting underlying, non-fuel product stream, and are thus excluded from the system boundary in the Board approved Tier 1 Calculator.")

[62] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(2).

[63] CAL. CODE REGS. TIT. 17 § 95488.9(f)(2)(B).

[64] CAL. AIR RES. BD., *Tier 1 Simplified CI Calculator Instruction Manual: Starch and Fiber Ethanol* (Aug. 13, 2018), *available at* https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

[65] Susanne Retka Schill, *Meeting the California Low Carbon Challenge*, ETHANOL PROD. MAGAZINE (Feb. 8, 2016), http://ethanolproducer.com/articles/13000/meeting-the-california-low-carbon-challenge.

role in two transportation fuel life cycles.[66] Some ethanol plants also incorporate factory farm gas from dairies as a process fuel, further lowering the ethanol's carbon intensity.[67] These "negative" upstream emissions from factory farm gas and negative downstream emissions from the use of distillers grains as dairy feed both reduce the LCFS carbon intensity of ethanol, which would likely not receive credits otherwise.

While downstream emissions from distillers grains in ethanol production are accounted for by excluding them from that fuel's carbon intensity calculation, the by-product of dairy and swine factory farm gas, digestate – which would *increase* the carbon intensity of factory farm gas – remains largely unaccounted for, even though the LCFS requires all Tier 2 pathway application lifecycle analyses to include:

> a description of all co-products, byproducts, and waste products associated with production of the fuel. That description shall extend to all processing, such as drying of distiller's grains, applied to these materials after they leave the fuel production process, including processing that occurs after ownership of the materials passes to other parties.[68]

Demonstrably, any storage, land-application, or composting of digestate falls within the meaning of the term 'process,' but the LCFS does not require, and no factory farm gas lifecycle analyses include emissions from digestate.

The process of anaerobic digestion can result in "changes in the manure composition" that alter ammonia (NH_3) and nitrous oxide (N_2O) emissions, depending upon the management strategy used.[69] In the United States, liquid effluent from factory farm gas production is primarily applied to land as fertilizer and digestate solids are composted and then land applied or used for bedding on-farm (See Figure 4 in Appendix C).[70] Digestate land application and composting result in emissions of nitrous oxide, which has a global warming potential 265 to 298 times that of carbon dioxide.[71] A recent study found that digested solids that were composted released such significant

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[66] Somerville, Scott, Daniel A. Sumner, James Fadel, Ziyang Fu, Jarrett D. Hart, and Jennifer Heguy, *By-Product Use in California Dairy Feed Has Vital Sustainability Implications*, ARE UPDATE 24(2) (2020) 5, University of California Giannini Foundation of Agricultural Economics.

[67] For example, a Tier 2 ethanol pathway for a plant in Pixley, California uses biomethane from dairies as a process fuel to transform starch from corn into ethanol. *GFP Ethanol, LLC dba Calgren Renewable Fuels GREET Pathway for the Production of Ethanol from Corn and Fueled by NG and Biogas from Two Local Dairy Digesters* (Sept. 20, 2018), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/t2n-1279_report.pdf.

[68] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(8).

[69] Michael A. Holly et al., *Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture*, 239 ECOSYSTEMS AND ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007.

[70] Ron Alexander, *Digestate Utilization in The U.S.*, 53 BIO CYCLE 56 (Jan. 2012), https://www.biocycle.net/digestate-utilization-in-the-u-s/. Mohanakrishnan Logan & Chettiyappan Visvanathan, *Management strategies for anaerobic digestate of organic fraction of municipal solid waste: Current status and future prospects*, 37 WASTE MGT. & RES. 27, 27 (Jan. 28, 2019), https://doi.org/10.1177/0734242X18816793.

[71] Holly, *supra* note 69 at 411. Alun Scott & Richard Blanchard, *The Role of Anaerobic Digestion in Reducing Dairy Farm Greenhouse Gas Emissions*, 13 SUSTAINABILITY 2 (Mar. 1, 2021) https://doi.org/10.3390/su13052612; *Understanding Global Warming Potentials*, ENV'T PROT. AGENCY, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials (last visited Oct. 21, 2021).

nitrous oxide emissions relative to undigested manure solids that the climate benefits of the captured methane from the digestion process were cancelled out.[72] Additionally, many operators choose to store digestate in open-air lagoons. Open-air storage can release methane, potentially negating methane captured during digestion, as well as ammonia, which is harmful to nearby communities in the San Joaquin Valley and a $PM_{2.5}$ precursor.[73]

Despite the significant emissions associated with digestate and the high global warming potential of methane and nitrous oxide, the LCFS fails to fully account for this inevitable by-product of factory farm gas production. Digestate treatment and storage is within the Tier 1 system boundary for anaerobic digestion of dairy and swine manure (described as "effluent"), but the pathway does not contemplate emissions associated with effluent after storage.[74] In contrast to Tier 1, the Tier 2 system boundary in the CA GREET3.0 calculator includes emissions from "AD Residue Applied to Soil," in other words, digestate that is land applied.[75] In practice, however, digestate is not mentioned in several recent Tier 2 applications for cluster projects.[76] Further, in responding to a comment criticizing a project's lack of accounting for digestate emissions, the applicant responded in a letter to CARB that "land application of effluent is outside of the scope of the project."[77] These contradictory descriptions of the system boundary as related to digestate highlight an inconsistent approach to the quantification of emissions from digestate. Moreover, neither the pathways nor the project application materials seem to account for digestate uses other than land application. This excludes any emissions associated with the solids composting. By failing to account for downstream emissions associated with land application and the massive nitrous oxide emissions from solids composting, CARB's life cycle analysis omits significant greenhouse gas emissions from factory farm gas production and further inflates the factory farm gas credit value.

The factory farm gas life cycle analyses also fail to include downstream emissions associated with transport. The LCFS factory farm gas pathways mention, but do not require reporting of inputs to calculate emissions generated from the refining and transport of factory farm gas. For example, the Tier 1 Calculator for factory farm gas *can* quantify emissions leaked or

[72] Holly, *supra* note 69 at 414, 418.

[73] *See generally* Yun Li et al., *Manure digestate storage under different conditions: Chemical characteristics and contaminant residuals*, 639 SCI. OF THE TOTAL ENV'T 19 (Oct. 15, 2018), https://doi.org/10.1016/j.scitotenv.2018.05.128 (discussing the impacts of open storage).

[74] CAL. AIR RES. BD., Tier 1 Simplified CI Calculator Instruction Manual: Biomethane from Anaerobic Digestion of Dairy and Swine Manure (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.63225775.1254208748.1633995805-239480191.1598055085.

[75] *LCFS Life Cycle Analysis Models and Documentation: California GREET3.0 Model,* CAL. AIR RES. BD., https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation (last visited July 29, 2021).

[76] *See* CAL. AIR RES. BD., *Fuel Pathway Table: Current Fuel Pathways*, *available at* https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities (last visited Oct. 19, 2021).

[77] Letter from Michael D. Gallo, Gallo Cattle Company Regarding "Tier 2 Pathway Application: Application No. B0089" (June 26, 2020), on file with CAL. AIR RES. BD., https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/b0089_response.pdf.

vented from the digester and associated pipeline infrastructure—but the applicant is not *required* to calculate it.[78]

In addition to the failure to account for various upstream and downstream emissions from factory farm gas production, the LCFS life cycle analyses do not address the fact that these emissions are associated with *intentionally created* methane. LCFS factory farm gas pathways are intended to credit "reduction[s] of greenhouse gas emissions achieved by the voluntary capture of methane" or "avoided methane emissions."[79] This structure is premised on the idea that the manure used to produce the gas is unavoidable waste, whose emissions would not otherwise be diverted. But the massive quantity of manure methane emissions that CARB seeks to mitigate is the result of the intentional liquification of the manure, one of multiple manure management methods. While necessary to produce factory farm gas, the production of vast quantities of liquified manure is by no means an inevitable result of dairy or pig farming.[80] Alternative manure management techniques are available. Techniques such as solid-liquid separation, scrape and vacuum collection of manure, composting, and pasture-based practices are all viable methods of manure management that would avoid the methane emissions caused by open-air lagoons of liquid manure. Preliminary findings from CARB's Dairy and Livestock Greenhouse Gas Emissions Working Group indicate that these methods of manure management may offer more cost-effective methane emissions reductions than anaerobic digestion and may deliver additional environmental and health benefits, such as reduced impact on water quality.[81] Avoiding manure generation and reducing the amount of manure that has to be managed is the best way to protect human and animal health, along with the environment (see Figure 3 in Appendix C on Waste Management Hierarchy).[82] But the LCFS program does the opposite of promoting dairy manure avoidance or even lower-emissions manure management practices. Instead, the LCFS program has created a new revenue stream for factory farms based on the manure itself – the source of the methane the program seeks to reduce – incentivizing the production and liquification of manure as though it were a cash crop.

Additionally, "even RNG from waste methane can have negative climate impacts relative to the most likely alternative of flaring, not venting, the methane."[83] Flaring, like other forms of combustion, converts methane to carbon dioxide, reducing the net emissions impact. Flaring is a ubiquitous, low cost means of reducing methane. Though flaring is not a sustainable means to

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[78] CAL. AIR RES. BD., *Tier 1 Simplified CI Calculator Instruction Manual: Biomethane from Anaerobic Digestion of Dairy and Swine Manure* 1, 8–9, 13–14 (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.153600376.1744114239.1608082460-1114251839.1598731081.
[79] CAL. CODE REGS. TIT. 17 § 95488.9(f).
[80] *Animal Agriculture in the U.S. – Trends in Production and Manure Management*, LIVESTOCK AND POULTRY ENV'T LEARNING CMTY. (Mar. 5, 2019), https://lpelc.org/animal-agriculture-in-the-u-s-trends-in-production-and-manure-management/.
[81] CAL. AIR RES. BD., *Findings and Recommendations: Subgroup 1: Fostering Markets for Non-digester Projects, Senate Bill 1383 Dairy and Livestock Working Group* 3 (Oct. 12, 2018), https://ww2.arb.ca.gov/sites/default/files/2020-11/dsg1_final_recommendations_11-26-18.pdf.
[82] A reduction of waste is the preferred management method in the Environmental Protection Agency's waste management hierarchy for decision-making. *Waste Management Hierarchy and Homeland Security Incidents,* ENV'T PROT. AGENCY, https://www.epa.gov/homeland-security-waste/waste-management-hierarchy-and-homeland-security-incidents (last visited Oct. 12, 2021).
[83] Emily Grubert, *At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates*, 15 084041 ENV'T RES. LETTERS Aug. 2020, 2.

reduce emissions, it should be the baseline to which any emissions reductions associated with anaerobic digestion are compared.

Moreover, because factory farm gas can be sold as a fuel and used to generate significant supplemental revenue from LCFS credits, over time "it is not only possible but expected…to increase methane production beyond what would have happened anyway."[84] Any manure production that has been incentivized by LCFS credit revenue will also result in intentionally created methane, which according to one recent study, *is always GHG-positive*.[85]

Finally, the Agro-Ecological Zone Emissions Factor (AEZ-EF) used to measure emissions from land-use change by CA-GREET3.0, and therefore by Tier 2 applicants, fails to account for the full impacts from the industrial dairy and pig facilities producing factory farm gas.[86] CARB's Executive Officer may require fuel producers to include six specific "feedstock/finished biofuel combinations," in their calculations.[87] These feedstocks include corn, sugarcane, sorghum grain ethanol, soy, canola, and palm biomass-based diesel.[88] Apart from land-use change related to livestock grazing (which is rarely relevant to industrial livestock operations), the AEZ-EF model does not address the land-use change associated with industrial dairy farming which are required for the production of factory farm gas.[89]

The overly narrow life cycle analysis in the factory farm gas pathways not only undermines the program's capacity to incentivize reductions, but violates AB 32's mandate that "[T]he state board shall rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by this section."[90] Scientific literature provides a more complete account of greenhouse gases emitted during the life cycle of factory farm gas produced from dairy and pig facilities. These analyses incorporate emissions from feed production, enteric fermentation, farm management and operations, and the treatment, use, or disposal of digestate residues produced during anaerobic digestion in addition to manure management emissions.[91] Omitting these essential stages from the LCFS factory farm gas pathways neglects a significant portion of emissions involved in producing

[84] *Id.* at 5.
[85] *Id*. at 4.
[86] CAL. CODE REGS. TIT. 17 § 95488.3.
[87] CAL. CODE REGS. TIT. 17 § 95488.3(d).
[88] *Id*.
[89] Richard J. Pelvin et al., *Agro-ecological Zone Emission Factor (AEZ-F Model): A model of greenhouse gas emissions from land-use change for use with AEZ-based economic models* 3, 31 (Feb. 21, 2014), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/lcfs_meetings/aezef-report.pdf.
[90] CAL. HEALTH & SAFETY CODE § 38562 (e). In Resolution 19-27, CARB itself stated that the LCFS "was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective reductions in GHG emissions from transportation fuel used in California." CAL. AIR RES. BD., RES. 19-27, *supra* note 55.
[91] *See, e.g.,* E. M. Esteves et al., *Life cycle assessment of manure biogas production: A review,* 218 J. CLEAN PROD. 411–423 (2019), https://doi.org/10.1016/j.jclepro.2019.02.091; E. Cherubini et al., *Life cycle assessment of swine production in Brazil: a comparison of four manure management systems*, 87 J. CLEAN PROD. 68–77 (2015), https://doi.org/10.1016/j.jclepro.2014.10.035; V. Paolini et al., *Environmental impact of biogas: A short review of current knowledge*, 53, J. ENV'T SCI. HEALTH A 899–906 (2018), https://doi.org/10.1080/10934529.2018.1459076.

manure and, as a result, the pathway treats manure as if it is produced from thin air or as if lagoons of liquid manure occur naturally in the San Joaquin Valley. [92]

The LCFS regulation mandates a full accounting of the aggregate life cycle emissions from a given fuel. In CARB Resolution 19-27, the agency reiterated that the "[d]etermination of a fuel's energy demand and carbon intensity value is based on a "well-to-wheel" analysis, which includes production and processing, distribution, and vehicle operation.[93] And yet the factory farm gas pathways leave glaring gaps in the life cycle analysis beyond the narrow system boundaries. The premise that manure originates in manure lagoons ready for capture with no attendant emissions defies logic, yet CARB has embraced this to create an absurdly low carbon intensity value and inflated credit generating industry.

2. The fuel pathways for biomethane from dairy and swine manure fail to ensure that credited emissions reductions are additional to reductions that would have otherwise occurred.

The LCFS prohibits awarding credits for emissions reductions that are already required by law.[94] As a market-based compliance mechanism, however, the LCFS must also prohibit the award of credits for "any other greenhouse gas emission reduction that otherwise would occur."[95] While CARB promulgated the LCFS as an early action measure, CARB designed and implemented the LCFS as a market-based compliance mechanism. CARB itself described the LCFS as a market-based mechanism when promulgating amendments to the LCFS:

> The LCFS is a market-based approach designed to reduce the carbon intensity of transportation fuels by 10 percent by 2020, from a 2010 baseline. It is important to note that the Cap-and-Trade Program and the LCFS program have complementary, but not identical programmatic goals: Cap-and-Trade is designed to reduce greenhouse gasses from multiple sources by setting a firm limit on GHGs; the LCFS is designed to reduce the carbon intensity of transportation fuels. As a market-based, fuel-neutral program, the LCFS provides regulated parties with flexibility to achieve the most cost-effective approach for reducing transportation fuels' carbon intensity. . . .

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[92] A Naranjo et al., *Greenhouse Gas, Water, and Land Footprint Per Unit of Production of the California Dairy Industry Over 50 Years*, 103 J. DAIRY SCI. 3760–3773 (2020), https://www.journalofdairyscience.org/article/S0022-0302(20)30074-6/pdf; C. Alan Rotz et. al., *The Carbon Footprint of Dairy Production Systems Through Partial Life Cycle Assessment*, 93 J. DAIRY SCI. 1266–1282 (2010), https://doi.org/10.3168/jds.2009-2162; C. Alan Rotz, *Modeling Greenhouse Gas Emissions from Dairy Farms*, 101 J. DAIRY SCI. 6675–6690 (2018) https://www.sciencedirect.com/science/article/pii/S002203021731069X.

[93] CAL. AIR RES. BD., RES. 19-27, *supra* note 55; *see also* CAL. AIR RES. BD., *Appendix D: Draft Environmental Analysis* (Jan. 2, 2015), https://ww2.arb.ca.gov/sites/default/files/classic/regact/2015/lcfs2015/lcfs15appd.pdf.

[94] *See* CAL. CODE REGS. TIT. 17 § 95488.9(f)(1)(B) ("A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that… the baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.")

[95] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

> ARB staff disagrees that the LCFS is fundamentally a command-and-control system. The LCFS is a fuel-neutral, market-based program that does not give preference to specific transportation fuels and instead bases compliance on a system of credits and deficits based on each fuel's carbon intensity. Carbon intensity (CI) is a measure of the GHG emissions associated with the various production, distribution, and consumption steps in the "life cycle" of a transportation fuel. It is difficult to respond with depth to this assertion because the commenter provides no specifics to support the claim that the LCFS is not market-based. Notably, the commenter does not describe what components of the program could be considered command-and-control.[96]

Additionally, CARB's descriptions of the LCFS program closely parallel the statute's definition of "market-based compliance mechanism." The defintion states in relevant part that a market-based compliance mechanism is: "A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases."[97] CARB explains that the LCFS has a "market for credit transactions," where "entities with credits to sell can opt to pledge credits into the market and entities needing credits must purchase their pro-rata share of these pledged credits."[98] CARB explains that credits are generated relative "to a declining CI benchmark for each year."[99] The LCFS exhibits many if not most of the features of a market-based compliance mechanism, including a Cap-and-Trade allowance-like system with yearly declinations,[100] transaction rules,[101] recordkeeping and auditing requirements,[102] an account system to manage credit transfers – the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS),[103] and a portal that applicants must use to demonstrate compliance,[104] among others. In addition to CARB's interpretation, designation, and treatment of the program as a market-based

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96 CAL. AIR RES. BD., *Final Statement of Reasons for Rulemaking, Including Summary of Comments and Agency Response* 679-681 (2015), *available at* https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/fsorlcfs.pdf. *See also* CAL. AIR RES. BD., *Responses to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations* at B4-42 (2018), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/rtcea.pdf (CARB responding, "Because the LCFS is a market-based mechanism…"); CAL. AIR RES. BD., *Staff Discussion paper: Renewable Natural Gas from Dairy and Livestock Manure 6* (April 13, 2017), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/041717discussionpaper_livestock.pdf (in which CARB staff note in 2017 discussion paper that additionality requirements for the LCFS *are* intended to be identical to those of the compliance offset protocol, "ensure any crediting is for GHG reductions resulting from actions not required by law or beyond business as usual").

97 CAL. HEALTH & SAFETY CODE § 38505(k). Note that this is one of two definitions provided.

98 CAL. AIR RES. BD., *LCFS Basics* (2019), *available at* https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited Oct. 12, 2021).

99 *Low Carbon Fuel Standard: About*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Oct. 12, 2021).

100 *See* CAL. CODE REGS. TIT. 17 §§ 95482 – 95486.

101 *See* CAL. CODE REGS. TIT. 17 § 95491.

102 *See* CAL. CODE REGS. TIT. 17 § 95491.1.

103 CAL. CODE REGS. TIT. 17 § 95483.2(b). ("The LRT-CBTS is designed to support fuel transaction reporting, compliance demonstration, credit generation, banking, and transfers.").

104 *See* CAL. AIR RES. BOARD, *Low Carbon Fuel Standard – Annual Reporting and Verification User Guide* 3-4 (Aug. 9, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/Reporting_and_Verification_User_Guide.pdf.

mechanism and the overall structure of the regulation evincing the same, the designation of California's LCFS as a market-based mechanism is ubiquitous in academic and technical literature.[105]

Because the LCFS is a market-based compliance mechanism, section 38562(d)(2) of the Health & Safety Code requires that CARB ensure greenhouse gas emissions reductions in the LCFS are "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur."[106] Additionality requirements are essential for market-based programs that operate with a declining emissions benchmark, like the LCFS. Because regulated parties are permitted to emit above the benchmark so long as they offset these emissions with the purchase of credits, the LCFS must ensure that credits reflect reductions that are additional to claim a net reduction. The additionality requirement enumerated in the LCFS currently is far too narrow. It requires only that reductions are "additional to any legal requirement for the capture and destruction of biomethane."[107] This weak language incorporates only one of the two prongs required by AB 32 and does not ensure that reductions are additional to those from other LCFS incentives. CARB should grant this petition and amend the LCFS to include the broader additionality requirement.

As implemented to date, the LCFS program allows generation, sale, and use of factory farm gas credits that are plainly not additional when the methane reductions attributed to these LCFS credits result from, and are attibuted to, other programs and revenue sources. The LCFS 1) allows the same emissions reductions to be counted and credited by multiple emission reductions programs; and 2) awards credits to facilities receiving public funding for anaerobic digesters and related infrastructure, even when that funding is contingent on the construction of this equipment.

Numerous state and federal funding opportunities, incentives, and other subsidies are available for anaerobic digestors at factory farms. The Aliso Canyon Mitigation Agreement that CARB negotiated with Southern California Gas Company (SoCalGas) legally requires SoCalGas to pay for methane reductions at factory farm dairies in California.[108] The parties intended the agreement to mitigate the harms from the most damaging man-made greenhouse gas leak in United States history – SoCalGas' ruptured well that released at least 109,000 metric tons of methane before it was sealed.[109] SoCalGas funds the construction of digesters, which are intended to mitigate the leaked methane, and receives "mitigation credits" for the associated emissions reductions. The conditions of the agreement legally require changes intended to reduce emissions

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[105] *See, e.g.,* CENTER FOR CLIMATE AND ENERGY SOLUTIONS, *Policy Considerations for Emerging Carbon Programs* 2 (June 2016), https://www.c2es.org/wp-content/uploads/2016/06/emerging-carbon-programs.pdf (describing Low Carbon Fuel Standards as an example of a market-based policy option, specifically of a baseline-and-credit program); *Regional Activities*, NATIONAL LOW CARBON FUEL STANDARD PROJECT, https://nationallcfsproject.ucdavis.edu/regional-activities/ (stating California's "LCFS is a market-based mechanism") (last visited Oct. 12, 2021).

[106] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

[107] CAL. CODE REGS. TIT. 17 § 95488.9(f)(1).

[108] *People v. Southern California Gas Company,* Case Nos. BC602973 & BC628120, Appendix A to Consent Decree, Mitigation Agreement, *available at* https://www.arb.ca.gov/html/aliso-canyon/aliso-canyon-mitigation-agreement.pdf?_ga=2.146452402.708596706.1633463951-1172357510.1559256345.

[109] CAL. AIR RES. BD., *Responses to Frequently Asked Questions: Aliso Canyon Litigation Mitigation Settlement*, https://ww3.arb.ca.gov/html/aliso-canyon/aliso-canyon-faqs.pdf?_ga=2.67705041.1139070712.1533833674-1489205872.1532954259.

and yet at least eight facilities that receive this funding have also applied for LCFS credits for biomethane production. California Bioenergy sought LCFS credits for the S&S, Moonlight, Hamstra, Trilogy, Maple, T&W, BV Dairy, and Western Sky dairies.[110] These eight dairies are among seventeen that participate in the Aliso Canyon Mitigation Agreement.[111] Under no circumstances should mitigation for the Aliso Canyon disaster simultaneously qualify for credits generated and used in the LCFS.

Furthermore, the Legislature has appropriated public funds from the Greenhouse Gas Reduction Fund (GGRF) for several years to secure climate benefits. The California DDRDP, funded through the GGRF, provides funding for factory farm gas infrastructure. The California Department of Food and Agriculture describes the DDRDP as "financial assistance for the installation of dairy digesters in California, which will result in reduced greenhouse gas emissions."[112] Since 2015, the DDRDP has funded 117 dairy projects through the DDRDP, for a total of $195,025,884, and for which the CDFA claims 21,023,793 MTCO2e of methane reductions.[113] CARB also claims these reductions in a report to the Legislature on the climate benefits from these grants.[114] At least eight of these dairy projects, and likely many more, have received DDRDP grants and sought LCFS credits. For instance, California Bioenergy sought LCFS credits for the S&S, Moonlight, Hamstra, Trilogy, Maple, T&W, BV Dairy, and Western Sky dairies, all of which received DDRDP grants.[115] Importantly, the DDRDP purports to limit how grant monies may be used, but it does not prohibit a project from generating LCFS credits.[116]

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110 *See* CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0185, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_cover.pdf; CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

111 CAL. AIR RES. BD., *Aliso Canyon Natural Gas Leak, List of dairies involved in the mitigation agreement*, https://www.arb.ca.gov/html/aliso-canyon/aliso-canyon-mitigation-project-dairy-sites.pdf?_ga=2.216890962.535652136.1632321175-1949797088.1632171356.

112 *Dairy Digester Research & Development Program*, CAL. DEPT. OF FOOD & AG., https://www.cdfa.ca.gov/oefi/ddrdp/ (last visited Oct. 19, 2021).

113 CAL. DEPT. OF FOOD & AG., *CDFA Dairy Digester Research and Development Program Flyer (Sept. 2021)*, *available at* https://www.cdfa.ca.gov/oefi/ddrdp/docs/DDRDP_flyer_2021.pdf. (A list of all project recipients can be found at CAL. DEPT. OF FOOD & AG., *Dairy Digester Research and Development Program Project-Level Data (Sept. 17, 2021),* https://www.cdfa.ca.gov/oefi/DDRDP/docs/DDRDP_Project_Level_Data.pdf.)

114 CAL. CLIMATE INVESTMENTS, *2021 California Climate Investments Annual Report*, Table 2 (2021), *available at* http://ww2.arb.ca.gov/sites/default/files/cap-and-trade/auctionproceeds/2021_cci_annual_report.pdf.

115 *See* CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0185 *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_cover.pdf; CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

116 *See 2020 DDRDP Request for Grant Applications,* CAL. DEPT. OF FOOD & AG., https://www.cdfa.ca.gov/oefi/DDRDP/docs/2020_DDRDP_RGA_Public_Comments.pdf (last visited Oct. 5, 2021) ("Once a project has been awarded funds, the project may not: • Change or alter their biogas end-use during the project term. • Change the herd size beyond the limits established by the existing dairy operation's permits during the project term. • Change ownership of the dairy and/or partnership entities… • Duplicate equipment or activities that will receive funding from the California Public Utilities Commission (CPUC) pilot project authorized by California Health and Safety Code Section 39730.7(d)(2) (e.g., interconnection costs). *Note: Biogas conditioning and clean-up costs are allowable under the DDRDP.* • Commercial dairy operations that have already accepted, or plan to accept a grant award by CDFA's Alternative Manure Management Program (AMMP).") (emphasis added). Note that by allowing DDRDP funds to cover upgrade costs and other costs that the CPUC incentives program cannot, the CDFA has ensured that factory farm gas projects can benefit from multiple funding sources.

Other public funds authorized by the Legislature subsidize factory farm gas projects seeking to interconnect with utility natural gas pipelines.[117] This additional source of funds quickly became oversubscribed, prompting the California Public Utilities Commission to double the size of the program, all paid for with proceeds from sales of Cap-and-Trade allowances.[118] The California Public Utilities Commission went a step further, proposing in 2017 that participants in the SB1383 dairy biomethane Pilot Program could avoid the costs associated with gas production equipment, specifically gathering lines and "treatment equipment."[119] In what would be a major break with California energy precedent, ratepayers got to foot the bill.[120]

Projects receiving public funds should not, under the principles of additionality, also generate LCFS credits that allow emissions elsewhere; in this situation public funds essentially allow a transportation fuel deficit holder to emit more greenhouse gases and allow the factory farm gas project to generate a financial windfall. Under no circumstances did the Legislature intend for this perverse result to occur.

This is not a hypothetical concern: CARB recently proposed approval of Tier 2 Pathway applications B0185 and B0198 for eight dairy digester projects that have received both Dairy

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[117] *See* CAL. PUB. UTILITIES COMM'N, Decision Adopting the Standard Renewable Gas Interconnection and Operating Agreement, R.13-02-008 COM/CR6/jnf at 12 (Dec. 17, 2020), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M356/K244/356244030.PDF ("D.15-06-029 created a $40 million monetary incentive program "to encourage potential biomethane producers to build and operate biomethane projects within California that interconnect with the utilities" in accordance with AB 1900 (Gatto, 2012). This monetary incentive program was subsequently codified by AB 2313 (Williams, 2016)…The $40 million approved by the CPUC for the monetary incentive program is currently fully subscribed and there is a wait list for an additional $38.5 million worth of project funding.").

[118] *See Id.* at 14 ("After weighing the benefit of increased biomethane capture and use against the modest reduction in the California Climate Credit necessary to fully fund all existing biomethane projects, including those on the waitlist, we find it appropriate to provide an additional $40 million in funding from Cap-and-Trade allowance proceeds for the monetary incentive program to fund the biomethane projects that are currently on the wait list, bringing total funding to $80 million.").

[119] Decision establishing the implementation and selection framework to implement the dairy biomethane pilots required by Senate Bill 1383 at 7-8 (Dec. 18, 2017), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352373.PDF (". . . [T]he biomethane producers should own and operate the digesters and the biogas collection lines and treatment equipment to remove hydrogen sulfide and water from the raw biogas. Although we do not allow utilities to own these facilities, the costs associated with the biogas collection lines and treatment equipment will be recovered from the transmission rates of utility ratepayers through a reimbursement to the dairy biomethane producer. Natural gas utilities will own and operate all facilities downstream of the biogas conditioning and upgrading facilities, including pipeline laterals from such facilities, to the point of receipt and any pipeline extensions.").

[120] *Id.* ("Historically the costs of gathering, gas conversion to pipeline quality specifications, transportation from a gas production site to a conversion facility, transportation from the conversion facility to the pipeline, and pipeline interconnection costs have been borne by California natural gas producers as part of the commodity cost of gas since the late 1980s, as 'gathering costs' that the CPUC has ruled should be assigned to gas producers . . . . For the purposes of the Dairy Pilots, and consistent with the language of SB 1383, we are allowing cost recovery of the biogas collection lines owned by dairy biomethane producers, and allowing utilities to own and operate pipelines that carry biomethane from biogas conditioning and upgrading facilities to existing utility transmission systems and the interconnection facilities, without changing the requirements of D.89-12-016 for non-renewable natural gas producers . . . .").

Digester Research Development Program (DDRDP) and Aliso Canyon settlement funds.[121] Both programs claim credit for the methane reductions associated with the digester projects. If the LCFS system grants credits for these same reductions and allows a deficit holder to use those credits to demonstrate compliance with the LCFS, the reductions will be without question not additional. This absurd result allows excessive emissions and CARB must grant this petition to ensure LCFS program integrity.[122]

A wide range of other state and federal financial assistance is available to factory farms to support the construction and implementation of factory farm gas systems. This public financing comes in the form of grants, "production incentive payments, low-interest financing, tax exemptions and incentives, and permitting assistance."[123] The California Energy Commission provides funding for factory farm gas development through its Natural Gas Research and Development program.[124] The program provides $100 million annually to various fuel transportation projects, including factory farm gas.[125] The Environmental Quality Incentives Program (EQIP) is a federal program that provides matching funds for agricultural operations to contract with Natural Resources Conservation Service to develop technology or infrastructure with environmental benefits, including the construction of anaerobic digestion infrastructure.[126] The Rural Energy for America Program also provides federal funds to develop factory farm gas systems. *See* 7 U.S.C. § 8107.

The LCFS is demonstrably and avowedly a market-based compliance mechanism and is thus properly subject to the requirements of section 38562(d)(2). As the forgoing demonstrates,

[121] These dairy digester projects also may participate in the California Public Utilities Commission pilot projects, as California Bioenergy projects, which would confer additional public funds. *See* CAL. PUB. UTILITIES COMM'N, Press Release: CPUC, CARB, and Department of Food and Agriculture Select Dairy Biomethane Proejcts to Demonstrate Connection to Gas Pipelines (December 3, 2018), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M246/K748/246748640.PDF.

[122] This has caused confusion in Tier 2 application comments. For example, in comments on several applications, the Chair of the Board for the Kings County Board of Supervisors commented to ask how these applicants could participate in the LCFS without double counting reductions, given that they also participated in bioMAT. CARB did not respond to the comments. *See* CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 61 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0106_verboon_comments.pdf (commenting on Tier 2 Application B0106); CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 60 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0105_verboon_comments.pdf (commenting on Tier 2 Application B0105); CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 59 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b104_verboon_comments.pdf (commenting on Tier 2 Application B0104).

[123] CAL. DAIRY CAMPAIGN, *Economic Feasibility of Dairy Digester Clusters in California: A Case Study* 45, (June 2013) https://archive.epa.gov/region9/organics/web/pdf/cba-session2-econ-feas-dairy-digester-clusters.pdf.

[124] *Natural Gas Research and Development Program*, CAL. ENERGY. COMM'N., https://www.energy.ca.gov/sites/default/files/2019-05/naturalgas_faq.pdf (last visited Oct. 18, 2021).

[125] *Clean Transportation Program*, CAL. ENERGY. COMM'N., https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program (last visited Oct. 18, 2021).

[126] Environmental Quality Incentives Program, NAT'L RES. CONS. SERVICE, https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/programs/financial/eqip/.

private and public funding either have been or could be used to reduce methane emissions from pig and dairy facilities.[127] The LCFS should not allow fuel producers to generate credits from such non-additional reductions that deficit holders then use to justify their excess emissions, undermining the integrity of the LCFS program.

3. CARB's crediting of non-additional reductions and the inflated credit value from CARB's failure to account for the full quantity of life-cycle emissions both incentivize increased manure generation and manure liquification and constitute a failure to achieve the maximum technologically feasible and cost-effective greenhouse gas emissions.

Including inflated credits and credits for non-additional reductions contravenes the fundamental purpose of the LCFS: to reduce greenhouse gas emissions associated with transportation fuels. Inflated credits and credits for non-additional reductions have the effect of increasing manure generation and liquification, and its associated greenhouse gas emissions. Additionally, by purchasing inflated credits, deficit generators can more easily meet their compliance obligations without reducing their emissions. As a result of these deficiencies, the LCFS fails to achieve the maximum technologically feasible and cost-effective emissions reductions.

The factory farm gas industry is currently made profitable by the LCFS and similar programs. In fact, "[w]ell over 50% of the revenue from most projects generating credits comes from the [LCFS and Federal RIN] credits."[128] A recent report by a private investment firm on the promising growth prospects for factory farm gas concluded that "operators are not in the business of producing RNG, they are in the business of monetizing RNG's environmental attributes through various federal and state programs."[129] This is by design: the goal of the LCFS factory farm gas pathways is to incentivize the development of factory farm gas as an alternative fuel. This goal assumes incentivizing development of factory farm gas will result in a net decrease in manure methane emissions. But this assumption – the result of the deficient life cycle analysis and inclusion of non-additional reductions – is mistaken.

Increased profitability and growth of the factory farm gas industry does not necessarily entail a reduction in manure methane emissions from participating factory farms. Due to the poor design of the LCFS pathways for factory farm gas, the program encourages not only capture of manure methane, as intended, but increased production of that methane. Revenue from LCFS credits is an increasingly enticing source of potential profit for many factory farms. In the case of

[127] For this reason, LCFS credits also should not be issued to facilities that already operate digesters to produce low-CI electricity but seek to convert to producing biomethane, as no truly additional emissions reductions occur upon switching fuel production pathways.

[128] Annie AcMoody & Paul Sousa, *Western United Dairies, Interest in California Dairy Manure Methane Digesters Follows the Money*, CoBANK, at 4, (Aug. 2020), https://www.cobank.com/documents/7714906/7715329/Interest-in-California-Dairy-Manure-Methane-Digesters-Follows-the-Money-Aug2020.pdf/be11d7d6-80df-7a7e-0cbd-9f4ebe730b25?t=1603745079998.

[129] STIFEL EQUITY RESEARCH, *Energy & Power – Biofuels: Renewable Natural Gas, A Game-Change in the Race for Net-Zero* (March 8, 2021), *available at* https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/60ad5a8802a04b71ca252414/1621973643907/Stifel+RNG+Analysis.pdf.

industrial dairy operations, these inflated credits provide certainty for operators seeking to maintain or expand herd sizes by providing significant additional income to supplement volatile milk revenue.[130] In 2017, CARB itself "assume[d] that California's LCFS credits [would] contribute revenue of $865,000" (assuming $100 per metric ton of CO_2).[131] The average LCFS credit price has increased significantly since this estimate was made, with 2020 prices hovering around $200 per metric ton of CO_2 (see Figure 5 in Appendix C). As a result, LCFS credits can be a more reliable income stream than milk. The LCFS not only encourages the development of factory farm gas systems but entrenches the underlying factory farms and even incentives expansion of these operations – the very sources of manure methane the factory farm gas credits are intended to reduce.

LCFS credits derive their value from recipients' ability to sell these credits to LCFS participants that generate deficits. Deficit-generating facilities include producers of conventional, high carbon intensity fuels such as gasoline and diesel fuels. This means that the life cycle analysis deficiencies and granting of credits for non-additional reductions not only incentivize increased emissions from factory farms, but also function to allow emissions in other transportation fuel industries.

Additionally, because economies of scale for anaerobic digesters favor larger herd sizes, factory farm gas producers have an incentive to produce more liquid manure, by either increasing herd size or participating in a digester cluster. This is the case for factory farm gas from both cows and pigs. In California, where most digesters use manure from lagoons to produce gas for pipeline transport, the technology requires a minimum of 2,000 cows to be economically feasible.[132] Scale is central to making the technology investment profitable, and "each additional 1,000 cows reduce the cost per cow of digester projects by 15-20%."[133] EPA AgSTAR admits that most methane digesters "are not economically viable until greater than 10,000 hogs are incorporated."[134]

The programmatic distortions described in parts III(A)(1) and (2) will drive the expansion of factory farms to supply factory farm gas, intentionally creating greenhouse gas emissions and localized pollution. CARB should rescind the factory farm gas pathways and preclude factory farm

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[130] The milk price that dairy farmers receive has fluctuated considerably over the past two decades while costs have remained relatively constant. In 2015 and 2016, dairies experienced negative average residuals (see Table 2 in Appendix C). In 2017, annual milk revenue from "a farm with 2,000 cows producing 230 hundredweight per cow per year (the average in the San Joaquin Valley)" totaled nearly $7.6 million based on the milk price of $16.50 per hundredweight. After factoring in 2017 cost estimates by the California Department of Food and Agriculture (CDFA), the "net revenue at the typical dairy in the southern San Joaquin Valley amounted to zero." *See* Justin Ellerby, CAL. CENTER FOR COOP. DEV., *Challenges and Opportunities for California's Dairy Economy* 5 (2010); William Matthews and Daniel Sumner, *Contributions of the California Dairy Industry to the California Economy in 2018*, UNIV. OF CAL. AGRIC. ISSUES CENTER 17-18 (2019), https://aic.ucdavis.edu/wp-content/uploads/2019/07/CMAB-Economic-Impact-Report_final.pdf; Hyunok Lee. & Daniel A. Sumner, *Dependence on policy revenue poses risks for investments in dairy digester,* 72 CAL. AG. 226-235, 231 (2018), https://doi.org/10.3733/ca.2018a0037.

[131] Hyunok Lee & Daniel A. Sumner, *supra* note 130 at 232.

[132] GLOBAL DATA POINT, *California Incentives Spur Dairy Manure Methane Digester Developments*, GALE: BUSINESS INSIGHTS (Doc. No. A631672444) (Aug. 6, 2020).

[133] *Id.*

[134] ENV'T PROT. AGENCY, *AgSTAR, Project Development Handbook: A Handbook for Developing Anaerobic Digestion/Biogas Systems on Farms in the United States* 7-2, n. 58, https://www.epa.gov/sites/default/files/2014-12/documents/agstar-handbook.pdf (3rd Ed.).

gas from the LCFS program. In the alternative, CARB must amend the regulation to ensure that the carbon intensity values account for the full life cycle of dairy and pig facility emissions, including production and pre-processing of manure feedstock and downstream emissions associated with digestate land application and composting, and prohibit credits from non-additional reductions.

B. The fuel pathways for biomethane from dairy and swine manure fail to maximize additional environmental benefits and interfere with efforts to improve air quality.

The California Legislature directed CARB to design regulations in a manner that considers overall societal benefits, including other benefits to the environment and public health, and ensure that activities taken pursuant to the regulations do not interfere with the state's efforts to improve air quality.[135] The Legislature also declared, in enacting AB 32, that it intended that CARB design reduction measures in a manner that "maximizes additional environmental and economic cobenefits for California, and complements the state's efforts to improve air quality."[136] But so long as the LCFS program includes factory farm gas and incentivizes factory farm expansions and the resulting air pollution, it cannot maximize environmental benefits or improve air quality. Moreover, given these impacts, CARB has not adequately considered overall societal costs in the regulation's design.

Monetizing a waste stream, like manure, does not eliminate that waste. The material impacts of manure (and later digestate) remain, whether or not it generates revenue for confined animal feeding operations. Nearby communities must still contend with the harms from the production, transportation, storage, and processing of this waste. If anything, monetizing a waste stream like manure exacerbates these harms by disincentivizing waste reduction. Incentivizing larger herd sizes and the liquification of more manure exacerbates existing pollution to air, water, and land, and the associated public health harms from industrial dairy and pig facilities, in addition to increased greenhouse gas emissions.[137] Additionally, factory farm gas technology creates new and additional environmental and public health harms, including through the storage, composting, and land application of digestate.

The 3.9 million residents of the San Joaquin Valley face increased health risks from breathing polluted air.[138] Industrial dairy operations emit the ammonia that contributes to the some

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[135] CAL. HEALTH & SAFETY CODE § 38562(b)(4) ("Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."); CAL. HEALTH & SAFETY CODE § 38562(b*)(*6) ("Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."). *See also* CAL. HEALTH & SAFETY CODE § 38562.5 (making section 38562(b) applicable to regulations adopted to achieve reductions beyond the statewide greenhouse gas emissions limit).

[136] CAL. HEALTH & SAFETY CODE § 38501.

[137] *EPA Activities for Cleaner Air - San Joaquin Valley,* U.S. ENV'T PROT. AGENCY, https://www.epa.gov/sanjoaquinvalley/epa-activities-cleaner-air (last updated Mar. 6, 2019).

[138] Rory Carroll, *Life in San Joaquin valley, the place with the worst air pollution in America*, THE GUARDIAN (May 13, 2016), https://www.theguardian.com/us-news/2016/may/13/california-san-joaquin-valley-porterville-pollution-poverty.

of the worst long-term and short-term $PM_{2.5}$ pollution in the United States, which causes health problems such as asthma and has been linked to premature death as described *supra* in part II.[139] Industrial dairies are also the largest source of volatile organic compounds (VOCs), which contribute to the Valley's ozone (smog) air pollution crisis.[140] The digestate from factory farm gas production can emit even more hazardous VOCs during storage. An analysis of digestate from pig manure identified nearly 50 VOCs, 22 of which are labeled hazardous by the EPA.[141] Of these 22 hazardous VOCs, "8 were identified to be or likely to be carcinogenic, and 14 were identified to be harmful to other human organs or systems."[142]

Biogenic and anthropogenic emissions of VOCs and nitrogen oxides (NOx) both form ground-level ozone, the concentration of which is "directly affected by temperature, solar radiation, wind speed and other meteorological factors."[143] VOCs from corn silage at dairies alone would be the largest source in the Valley, with such emissions forming more ozone than the VOCs emitted by passenger vehicles.[144] Breathing in ground-level ozone can trigger a variety of dangerous health problems like throat irritation, chest pain, and congestion. It can also lead to severe lung damage, making infants and the elderly more vulnerable to health effects.[145] Ozone causes respiratory inflammation, increased hospital admissions for respiratory illness, decreased lung function, enhanced respiratory symptoms for people with asthma, increased school absenteeism, and premature mortality.[146] Evidence indicates that "adverse public health effects occur following exposure to elevated levels of ozone, particularly in children and adults with lung disease."[147] The San Joaquin Valley is classified as an extreme ozone nonattainment area for the 1997 and 2008 8-hour ozone standards.[148]

Industrial dairies are also the largest source of ammonia.[149] Factory farm gas production adds even more ammonia to San Joaquin Valley air: ammonia emissions from digestate increased 81% relative to raw manure.[150] Anaerobic digestion causes this increase in ammonia emissions, "due to an increased concentration of ammoniacal nitrogen."[151] In addition to its unpleasant odor,

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139 *Id.*
140 *See* SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DIST., *2016 Plan for the 2008 8-Hour Ozone Standard, Appendix B*, *available at* http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/b.pdf.
141 Yu Zhang et al., *Characterization of Volatile Organic Compound (VOC) Emissions from Swine Manure Biogas Digestate Storage*, 10 ATMOSPHERE 1, 7 (2019), https://doi.org/10.3390/atmos10070411.
142 *Id.* at 8.
143 73 FED. REG. 16436, 16437 (March 27, 2008).
144 *See* Cody J. Howard, et al., *Reactive Organic Gas Emissions from Livestock Feed Contribute Significantly to Ozone production in Central California*, 44 ENV'T SCI. TECHNOL. 7 2309–2314 (2010), https://pubs.acs.org/doi/abs/10.1021/es902864u.
145 *Id.*
146 73 Fed. Reg. 16436, 16440 (March 27, 2008).
147 83 FED. REG. 61346, 61347 (November 29, 2018).
148 75 FED. REG. 24409 (May 5, 2010); 77 FED. REG. 30088, 30092 (May 21, 2012).
149 SAN JOAQUIN VALLEY AIR CONTROL DIST., 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, Appendix B and Appendix G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf and http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
150 *See* Holly, et al., *Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land disposal*, AG., ECOSYSTEMS AND ENV'T 239 (2017) 410–419, https://www.researchgate.net/publication/313731233_Greenhouse_gas_and_ammonia_emissions_from_digested_and_separated_dairy_manure_during_storage_and_after_land_application.
151 *Id.*

which degrades quality of life for nearby residents, ammonia "is corrosive and can be a powerful irritant to skin, eyes, and digestive and respiratory tissues."[152] Ammonia also reacts with oxides of nitrogen to form ammonium nitrate, the most significant component of the San Joaquin Valley's $PM_{2.5}$ pollution problem.[153] Homes located within a quarter mile of a dairy confined animal feeding operation have experienced higher concentrations of both ammonia and particulate matter.[154] In addition to the harms of PM2.5 describes above, larger particles of dust pollution from factory farm dairies also carry harmful allergens and endotoxins to nearby homes.[155] Endotoxins are a "powerful inflammatory agent" that can interact with other components and lead to respiratory issues, and allergens can worsen asthma symptoms.[156] A study in rural Washington found that higher exposure to pollution from confined animal feeding operations was associated with degraded lung function in children with asthma living nearby.[157]

Depending on the physical characteristics (temperature, pH, total solid content) and the speed and frequency of the mixing process used to treat it, digestate from factory farm gas production can release dangerous concentrations of hydrogen sulfide.[158] High hydrogen sulfide emission levels are associated with a total solid content of seven percent, "which is the most appropriate for pumping and mixing of dairy manure."[159] Increasing the speed and frequency of mixing while in storage can also contribute to higher hydrogen sulfide emissions from digestate.[160] These emissions can have severe impacts on human health, particularly farm workers, and can even lead to death.[161] Furthermore, hydrogen sulfide may be detected on fields where manure is sprayed for fertilizer, and the gaseous substance can be dispersed by the wind.[162] Hydrogen sulfide gas is a respiratory tract irritant and in higher concentrations or with longer exposure, it can cause a pulmonary edema.[163] The acute symptoms of hydrogen sulfide exposure include nausea, headaches, delirium, disturbed equilibrium, tremors, convulsions, and skin and eye irritation.[164]

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[152] D'Ann L. Williams et al., *Airborne cow allergen, ammonia and particulate matter at homes vary with distance to industrial scale dairy operations: an exposure assessment*, 10 ENV'T HEALTH 1, 3 (2011), https://doi.org/10.1186/1476-069X-10-72.

[153] SAN JOAQUIN VALLEY AIR CONTROL DIST., *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards*, Appendix B and Appendix G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf and http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.

[154] D'Ann Williams et al., *Cow allergen (Bos d2) and endotoxin concentrations are higher in the settled dust of homes proximate to industrial-scale dairy operations*, 26 J. EXPOSURE SCI. ENV'T EPIDEMIOLOGY 42, 46 (2016) https://doi.org/10.1038/jes.2014.57.

[155] *Id.*

[156] *Id.* at 42.

[157] Christine Loftus et al., *Estimated time-varying exposures to air emissions from animal feeding operations and childhood asthm*a, 223 INT. J. OF HYGIENE AND ENV'T HEALTH 192 (2020) https://doi.org/10.1016/j.ijheh.2019.09.003.

[158] Fetra J. Andriamanohiarisoamanana et al., *Effects of handling parameters on hydrogen sulfide emission from stored dairy manure*, 154 J. ENV'T MGMT. 110, 112-115 (2011), https://doi.org/10.1016/j.jenvman.2015.02.003.

[159] *Id.* at 115.

[160] *Id.* at 114.

[161] *Id.* at 110.

[162] *See* Agency for Toxic Substances and Disease Registry, Toxicological Profile for Hydrogen Sulfide and Carbonyl Sulfide, DEP'T OF HEALTH AND HUMAN SERVICES 27-138 (2016), https://www.atsdr.cdc.gov/toxprofiles/tp114.pdf; *See also* Amy Schultz et al., *Residential proximity to concentrated animal feeding operations and allergic and respiratory disease*, 130 ENV'T INT. 104911, 1 (2019), https://doi.org/10.1016/j.envint.2019.104911.

[163] *See* Agency for Toxic Substances and Disease Registry, *supra* note 162 at 27-138.

[164] *Id.*

Finally, inhalation of high concentrations or long-term exposure to hydrogen sulfide can result in extremely rapid unconsciousness and eventual death.[165]

Factory farm dairies also pollute the San Joaquin Valley's groundwater, primarily through the disposal of manure by land application on crops, which causes severe public health impacts to nearby communities. The Valley contains about half of California's 300 public water systems that currently serve unsafe drinking water.[166] This number does not include private wells and water systems serving fewer than 15 households. Unsafe water systems are concentrated in small towns and unincorporated communities.[167] Common pollutants in water from factory farm runoff include nitrogen, phosphorus, heavy metals, and pharmaceuticals.[168]

Nitrate contamination of water resources is one of the most widely documented environmental impacts in California's dairy-producing regions. Most nitrate contamination comes from chemical fertilizers and animal manure applied to fields.[169] Nitrogen application often far exceeds the crops' rate of nutrient intake and the soil's ability to absorb nutrients, which then leach into groundwater.[170] A study by University of California Davis found that 96% of nitrate pollution in the region comes from nitrogen applied to cropland, a third of which is in the form of animal manure.[171] The 2019 Central Valley Dairy Representative Monitoring Program reported that nitrate concentrations exceeded the maximum contaminant level in groundwater at all of the 42 dairy facilities.[172] The program identified the application of manure to crop fields as the main source of groundwater contamination, while finding other unaccounted nitrogen sources – too many cows – at the dairy facilities contributing to the excessive nitrate contamination.[173]

Between 1999 and 2008, seven out of eight counties in the San Joaquin Valley had above-average rates of Sudden Infant Death Syndrome which can be caused by nitrate contamination. 70% of San Joaquin Valley households believed their tap water to be unsafe when surveyed in 2011, and nitrate pollution still appears to be rising.[174] A 2016 study that mapped out the mass flows of nitrogen in the San Joaquin Valley, estimated that the health costs of total nitrate leaching to groundwater caused $500 million per year in health damages.[175] Application of biogas digestate, either as a liquid or composted solids,[176] will continue the trend in nitrate contamination in the San

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165 *Id.*

166 J.A. Del Real, *They Grow the Nation's Food, but They Can't Drink the Water*, N.Y. TIMES (May 21, 2019), https://www.nytimes.com/2019/05/21/us/california-central-valley-tainted-water.html.

167 *Id.*

168 JoAnn Burkholder et al., *Impacts from Waste from Concentrated Animal Feeding Operations on Water Quality*, 115 ENV'T HEALTH PERSPECTIVES 308, 308 (2007), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC1817674/.

169 *The Sources and Solutions: Agriculture*, U.S. ENV'T PROT. AGENCY, https://www.epa.gov/nutrientpollution/sources-and-solutions-agriculture (last updated July 30, 2020).

170 *Id.*

171 Harter et al., *Addressing Nitrate in California's Drinking Water with a Focus on Tulare Lake Basin and Salinas Valley Groundwater*, CENTER FOR WATERSHED SCI., UNIV. CAL., DAVIS, 17 (2012).

172 CENTRAL VALLEY DAIRY REP. MONITORING PROG., *Summary Representative Monitoring Report* at 8 (Revised 2020).

173 *Id.*

174 *Id.* at 28.

175 Ariel I. Horowitz et al., *A multiple metrics approach to prioritizing strategies for measuring and managing reactive nitrogen in the San Joaquin Valley of California*, 11 ENV'T RES. LETTERS 1, 11 (2016).

176 Roger Nkoa, *Agricultural benefits and environmental risks of soil fertilization with anaerobic digestates: A review*, 34 AGRON. SUSTAIN. DEV. 473, 473–492 (2014).

Joaquin Valley in particular, compounding the increase from the LCFS's subsidizing increased manure production.

In addition to the emissions from digestate storage and land application, certain Tier 2 anaerobic digester facilities generate additional air pollutants using factory farm gas to power internal combustion engines that generate electricity onsite.[177] According to a 2015 study commissioned by CARB, this form of electricity generation produces criteria air pollutants, like NOx and particulate matter.[178] Furthermore, the study found this technology would increase NOx emissions by 10 percent, exacerbating air quality in the Valley, in violation of CARB's duty to ensure that its programs do not interfere with efforts to reduce air pollution.[179] The San Joaquin Valley Unified Air Pollution Control District also documents criteria pollutant emissions from electricity generation from factory farm gas.

For example, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site.[180] And this project, as permitted by the Air District with required pollution control technology, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM10, and 3.18 tons/year of VOC.[181] Compared to a natural gas combined cycle plant in Avenal permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, SOx, and VOC emissions per unit of electricity generated.[182] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase offset emission reduction credits for the toxic air pollution emitted.[183] This facility *increases* air pollution. But California Bioenergy also sought for LCFS credits under a Tier 2 pathway application for the Lakeview Dairy project.[184] By allowing polluting facilities like Lakeview Dairy to generate credits for "renewable" natural gas, despite the harmful health impacts associated with emissions from the use of factory farm gas to generate electricity, CARB ignores its statutory obligation not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[185]

Because the LCFS has resulted in and will continue to incentivize an increase in dangerous pollution to the air, water, and land of the San Joaquin Valley, it fails to comply with section

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177 Arnaud Marjollet, *District Notice of Preliminary Decision*, San Joaquin Valley: Air Pollution Control (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf; *see also* CAL. AIR RES. BD., Staff Summary, Tier 2 Pathway Application B0104, Lakeview Dairy, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
178 Marc Carreras-Sospedra et al., *Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California* at 9-10 (Feb. 2015), https://ww2.arb.ca.gov/sites/default/files/classic//research/apr/past/11-307.pdf.
179 *Id*. at 4, 13.
180 Arnaud Marjollet, *supra* note 177.
181 *Id*. at 14.
182 Brent Newell, *Comments filed to California Energy Commission*, 4 (July 11, 2017), *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=220110&DocumentContentId=29811; Arnaud Marjollet, *supra* note 177 at 20.
183 *Id*.
184 CAL. AIR RES. BD., Staff Summary, Tier 2 Pathway Application B0104, Lakeview Dairy, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
185 CAL. HEALTH & SAFETY CODE § 38562 (b).

38562(b) (4) and (6) of the Health and Safety Code. Additionally, the LCFS program violates the Legislature's intent, expressed in section 38501(h) of the Health and Safety Code, to maximize additional environmental benefits. CARB should grant this petition and exclude factory farm gas from the program to address these violations.

IV. CARB MUST EVALUATE AND AMEND THE LCFS TO REMEDY ITS DISPROPORTIONATE ADVERSE AND CUMULATIVE IMPACTS ON LOW-INCOME AND LATINA/O/E COMMUNITIES IN VIOLATION OF STATE AND FEDERAL LAW.

CA 11135 and Title VI of the Civil Rights Act impose an affirmative duty on CARB to ensure that its policies and practices do not have a discriminatory impact on the basis of race.[186] CA 12955 additionally prohibits any practice or program that has a discriminatory effect on members of protected classes with respect to housing opportunities, including with respect to the use and enjoyment of dwellings.[187] AB 32 requires CARB to ensure any activities undertaken in compliance with the statute do not disproportionately impact low-income populations, consider the social costs of greenhouse gas emissions, and design regulations in a manner that is equitable. CARB must assess and prevent the disparate impacts imposed by the LCFS to avoid further harm to communities and to comply with California and federal law.

A. LCFS credits and the subsequent trading of those credits incentivize activities that result in public health and environmental harms in disproportionately low-income and Latina/o/e communities, particularly in the San Joaquin Valley.

The LCFS harms communities that are disproportionately Latina/o/e and low-income. These harms stem from (1) the generation of revenue for factory farms in proportion to the amount of manure they produce, (2) the encouragement of anaerobic digestion resulting in additional environmental harms related to digestate, and (3) allowing credits to offset emissions and toxic air pollutants elsewhere in California. Each of these harms impact disproportionately low-income and Black, Indigenous, or People of Color communities.

In California, the award of LCFS credits for factory farm gas and the harms these credits incentivize are concentrated in the San Joaquin Valley.[188] Part III(A)(3) shows how the LCFS has the effect of exacerbating existing adverse impacts from factory farms by incentivizing increased production and liquification of manure. Part III(B) describes the extensive environmental and public health harms associated with the increase in liquified manure, as well as the new harms

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[186] CAL. GOV'T CODE § 11135; 42 U.S.C. § 2000d.

[187] CAL. GOV'T CODE § 12955.8; CAL. CODE REGS. TIT. 2 § 12161.

[188] The San Joaquin Valley hosts 89% of the state's dairy cow population, and all but one of its counties are ranked nationally for milk sales (See Table 3, Appendix C). CAL. DEP'T OF FOOD AND AGRIC., Small Dairy Climate Action Plan 1 (2018), https://www.cdfa.ca.gov/oefi/research/docs/CDFA_Summary_of_Final_Report.pdf; *See* Lori Pottinger, *California's Dairy Industry Faces Water Quality Challenges*, Public Institute of California (May 20, 2019), https://www.ppic.org/blog/californias-dairy-industry-faces-water-quality-challenges/ (all 117 DDRDP projects are in the Valley).

from digestate. Incentivizing expansion of factory farms may also negatively affect community and economic growth.[189] Part II shows that San Joaquin Valley communities impacted by these new and exacerbated harms are disproportionately Latina/o/e and disproportionately low-income. Part II also describes the preexisting cumulative harms impacting these communities: San Joaquin Valley residents experience "the worst" air pollution nationally, and high levels of drinking water and groundwater contamination, largely due to agricultural runoff.[190]

The LCFS's market-based structure shapes the distribution of adverse impacts imposed by its incentives. In addition to the harmful activities incentivized at credit-generating factory farm gas facilities, the LCFS facilitates harm by the deficit-generating facilities that purchase credits. In order to provide for the trading of credits and deficits, LCFS treats greenhouse gas emissions as fungible. This approach allows CARB to justify the greenhouse gas emissions from gasoline and diesel, for example, in excess of the program's benchmark when the producers of these fuels purchase the equivalent credits. This is viewed by CARB as a positive attribute of the LCFS program because it "lets the market decide" how to achieve the targeted emissions reductions. But treating emissions as fungible ignores the localized impacts of co-pollutants associated with the production, transport, and combustion of various transportation fuels. These harms do not disappear simply because a gasoline producer pays to justify its polluting practices. The sale of factory farm gas credits to LCFS deficit generators prolongs their ability to pollute, rather than make direct emissions reductions.

Given that LCFS deficit generators include producers of conventional fuels, such as gasoline, diesel, and compressed natural gas, there is good reason to believe that LCFS deficit generating industries may disproportionately harm low-income and Black, Indigenous, and People of Color – specifically Latina/o/e – communities. The vast majority of California oil and gas production is concentrated in the San Joaquin Valley and around Los Angeles.[191] California communities living in proximity to oil and gas extraction are known to be disproportionately low income and Latina/o/e.[192] In the San Joaquin Valley, the oil and gas industries are concentrated in Kern County, where residents are subject to the cumulative harms of petrochemical extraction in

[189] Research indicates that "concentration and industrialization of agricultural production removes more money from the community of which the farm is located than when smaller farms operate in the area." CHELSEA MACMULLAN, HUMANE SOC'Y OF THE U.S., DAIRY CAFOS IN CALIFORNIA'S SAN JOAQUIN VALLEY at 26 (2007), https://www.humanesociety.org/sites/default/files/archive/assets/pdfs/farm/macmullan_apa-2007_final.pdf. The ratio of payroll versus emissions produced by concentrated factory farm dairies ranks worse than the petroleum industry. *Id*. at 27. Additionally, factory farm dairy employees face greater health risks because of their proximity to air pollutants and bacteria. Working in the industry has been associated with respiratory diseases such as Chronic Bronchitis, Occupational Asthma, and Pharyngitis. *Id*. at 29. Lack of access to healthcare due to language barriers or undocumented status likely exacerbates these harms. *Id*.

[190] *See* Carroll, *supra* note 138; *see also* Burkholder, *supra* note 168 at 308.

[191] Judith Lewis Mernit, *The Oil Well Next Door: California's Silent Health Hazard*, YALE ENV'T 360 (March 31, 2021), https://e360.yale.edu/features/the-oil-well-next-door-californias-silent-health-hazard ("Kern County, as the southern end of the San Joaquin Valley, produces 70 percent of California' oil; the bulk of the rest comes out of Los Angeles.")

[192] *See, e.g.* Kyle Ferrar, *People and Production: Reducing Risk in California Extraction,* FRACTRACKER ALLIANCE, (Dec. 17, 2020), https://www.fractracker.org/2020/12/people-and-production/; John C. Fleming et al., *Disproportionate Impacts of Oil and Gas Extraction on Already "Disadvantaged" California Communities: How State Data Reveals Underlying Environmental Injustice*, https://www.essoar.org/doi/pdf/10.1002/essoar.10501675.1 (concluding that 77% of permits for oil and gas wells were issued in "communities with a higher-than-average percentage of residents living in poverty and/or communities with a majority non-white population").

addition to those of factory farm dairies. As noted in part II, Kern County has seen a recent increase in LCFS applications for factory farm gas pathways. Residents of Kern County already experience higher than average rates of Chronic Lower Respiratory Disease (CLRD), asthma, and respiratory system cancers.[193] The death rate from CLRD in Kern County from 2013 to 2016 was twelve times higher than the state's CLRD death rate during the same time period.[194] Exacerbation of CLRD cases is a primary reason for CLRD-related deaths.[195] In 2015 to 2016, 31.1% of children in Kern County had been diagnosed with asthma at some point in their life, compared to 15.2% of children statewide and 13.7% and 10.3% in Los Angeles County and Sacramento County, respectively.[196]

In addition to emissions from extraction and refining of these polluting fuels, LCFS credits can also be used to offset emissions from the combustion. The co-pollutants from these emissions likely impose disproportionate adverse impacts on low-income and Black, Indigenous, and People of Color communities in California. A 2014 analysis found that exposure to $PM_{2.5}$ from cars, trucks, and buses "is not equally distributed" across California.[197] More specifically, the analysis concluded that on average, "African American, Latino, and Asian Californians are exposed to more $PM_{2.5}$ pollution from cars, trucks, and buses than white Californians. These groups are exposed to $PM_{2.5}$ pollution 43, 39, and 21 percent higher, respectively, than white Californians."[198] Additionally, "[T]he lowest-income households in the state live where $PM_{2.5}$ pollution is 10 percent higher than the state average, while those with the highest incomes live where PM2.5 pollution is 13 percent below the state average."[199] Given that California's major diesel trucking corridors, Interstate 5 and State Highway 99, both run north-south directly through the San Joaquin Valley,[200] emissions from combustion of deficit-generating transportation fuels may well impose additional cumulative impacts on the same communities impacted by dairy factory farms as well as fossil fuel extraction and refining.

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[193] Yongping Hao et al., *Ozone, Fine Particulate Matter, and Chronic Lower Respiratory Disease Mortality in the United States*, 192(3) AM. J. OF RESPIRATORY AND CRITICAL CARE MED. 337, 337–341, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4937454/.
[194] Nick Perez, *Despite decades of cleanup, respiratory disease deaths plague California county*, ENV'T HEALTH NEWS (Dec. 4, 2018) https://www.ehn.org/chronic-respiratory-disease-california-2621765230/pollution-persists.
[195] Elizabeth Oelsner et al., *Classifying Chronic Lower Respiratory Disease Events in Epidemiologic Cohort Studies*, 13 ANNALS OF THE AM. THORACIC SOC'Y 1057, 1057 (July 2016) https://doi.org/10.1513/AnnalsATS.201601-063OC.
[196] *Summary: Asthma*, KIDSDATA, https://www.kidsdata.org/topic/45/asthma/summary?gclid=Cj0KCQiAst2BBhDJARIsAGo2ldWxDuxZNs3gzxS4Qj3s048YVqkp4LWQ_nwYs7DSID4FDRTTdSsgq1waAgyxEALw_wcB (last visited Oct. 21, 2021).
[197] UNION OF CONCERNED SCI., *Inequitable Exposure to Air Pollution from Vehicles in California 1 (Feb. 2019)*, https://www.ucsusa.org/sites/default/files/attach/2019/02/cv-air-pollution-CA-web.pdf
[198] *Id.*
[199] *Id.* at 2.
[200] David Lighthall and John Capitman, *The Long Road to Clean Air in the San Joaquin Valley: Facing the Challenge of Public Engagement* 8 (Dec. 2007), CENTRAL VALLEY HEALTH POL'Y INST., https://chhs.fresnostate.edu/cvhpi/documents/cvhpi-air-quality-report07.pdf

B. CARB must amend the LCFS regulation to come into compliance with CA 11135, CA 12955, and Title VI of the Civil Rights Act of 1964 and to prevent further discrimination.

CARB has an affirmative duty under CA 11135 to ensure that its policies and practices do not disproportionately impact residents on the basis of race, color, national origin, or ethnic group identification.[201] CA 11135's prohibition on discrimination applies to the LCFS because it meets the criteria of a program that is "conducted, operated, or administered" by CARB, a California state agency.[202] CA 12955 prohibits activities that limit housing opportunities for members of protected classes, including activities and programs that interfere with the use and enjoyment of one's dwelling or that results in the location of toxic, polluting, and/or hazardous land uses in a manner that adversely impacts the enjoyment of residence, land ownership, tenancy, or any other land use benefit related to residential use. The state is subject to the prohibitions included in the Fair Employment and Housing Act.[203] Title VI of the Civil Rights Act of 1964 and implementing regulations prohibit disparate impact discrimination on the basis of race by recipients of federal funds.[204] As a recipient of federal funding, CARB is subject to Title VI.[205]

As described above, the LCFS exacerbates harms in some San Joaquin Valley communities twice over: once when it incentives the expansion of factory farm dairies and anaerobic digestion, and again when the resulting credits are sold to justify the pollution from conventional transportation fuel production, distribution, and combustion. Some (and likely all) of these harms are imposed on communities that are disproportionately Latina/o/e. Additionally, the LCFS has the effect of defeating one of the objectives of AB 32 on a discriminatory basis: to maximize additional environmental benefits and complement efforts to reduce air pollution.

Not only are there "equally effective alternative practices" to achieve the goal of reducing transportation emissions, there are alternative practices that are demonstrably both more effective and less discriminatory.[206] Reducing net greenhouse gas emissions from transportation fuels is an important and legitimate goal. Sadly, the LCFS factory farm gas pathways fail to accomplish it. Therefore, California's greenhouse gas emissions targets provide no credible justification for the LCFS's discriminatory impacts. Moreover, there are other, less harmful agricultural practices that CARB could encourage to reduce net emissions. Rather than monetize the source of greenhouse gas emissions and related co-pollutants, CARB could encourage the direct reduction of emissions at their source by supporting practices such as solid-liquid separation, scrape and vacuum

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201 CAL. GOV'T CODE § 11135.
202 *Id.*
203 CA Legis. 352 (2021), CAL. LEGIS. SERV. CH. 352 (A.B. 948), amending CAL. GOVT CODE 12955; 2 CCR 12005(v); 2 CCR 12060.
204 42 U.S.C. §2000d; 40 C.F.R. §7.
205 CARB has received funds EPA, including, for example, over $11.8 million in 2020 to administer the Diesel Emissions Reduction Act. Soledad Calvino, *U.S. EPA awards over $11.8 million for clean diesel projects in California*, U.S. ENV'T PROT. AGENCY (San Francisco), Aug. 30, 2020, News Release, https://www.epa.gov/newsreleases/us-epa- awards-over-118-million-clean-diesel-projects-california.
206 *See, e.g., Elston v. Talladega Count.*, 997 F. 2d at 1413.

collection of manure, composting, and pasture-based practices. Similarly, there are less harmful policy tools that could be used to produce these reductions.[207]

CARB bears the duty to evaluate the potentially discriminatory impacts of its policies and practices and to prevent these harms in the first place, which it failed to do in the design of the LCFS regulation and fails to do on an ongoing basis. To bring the LCFS into compliance with its civil right obligations, CARB must cease and desist from operating the LCFS program in such a way that results in unlawful, discriminatory impacts as proscribed by CA Gov't Code Sections 11135 and 12955, et seq., and Title VI of the Civil Rights Act of 1964. To this end, CARB must a) conduct a disparity analysis to evaluate the program and b) amend the LCFS regulation to ensure that it does not continue to disproportionately harm low-income and Latina/o/e communities. A disparity analysis must include an evaluation of the distribution of impacts from incentives created by credit generation, direct emissions from deficit generators facilitated by the trading of LCFS credits, and the distribution of emissions from the combustion of these fuels.[208]

C. CARB failed to design the LCFS regulation in a manner that is equitable and fails on an ongoing basis to consider the social costs of greenhouse gas emissions and ensure that the LCFS does not disproportionately impact low-income communities.

AB 32 mandated several safeguards to ensure equity and protect low-income communities in California from potential adverse impacts associated with the act's implementation. Section 38562(b)(2) of California Health and Safety Code requires that CARB design regulations "in a manner that is equitable" and "[ensure] that activities undertaken to comply with the regulations do not disproportionately impact low-income communities" to the extent feasible.[209] Section 38562(b)(2) also mandates that CARB "consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."[210] Section 38562.5 further mandates that, "when adopting rules and regulations pursuant to this division to achieve emissions reductions beyond the state greenhouse gas emissions limit and to protect the state's most impacted and disadvantaged

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[207] Environmental justice critiques of pollution trading schemes for their tendency to result in localized pollution that disproportionately impacts low-income and people of color communities are longstanding. *See, e.g., Environmental Justice Advocates Blast Emissions Trading Guide*, 10 INSIDE EPA'S CLEAN AIR REPORT 9, 6-7 (April 29, 1999), *available at* https://www.jstor.org/stable/48520963; Lily N. Chinn, *Can the Market Be Fair and Efficient? An Environmental Justice Critique of Emissions Trading*, 26 *Ecol. L. Quart.* 1 (1999), http://www.jstor.org/stable/24114004; Letter to the Biden-Harris Transition Team Re: EPA Administrator Appointment from Over 70 Environmental Justice Groups (December 2, 2020), *available at* https://1bps6437gg8c169i0y1drtgz-wpengine.netdna-ssl.com/wp-content/uploads/2020/12/2020-12-2-Nichols-letter.pdf.

[208] LCFS fuels originating from factory dairy farms include electricity, renewable natural gas, hydrogen, bio-compressed natural gas, bio-liquefied natural gas, and bio-liquefied-regasified-and recompressed (Bio-L-CNG). CAL. CODE REGS. TIT. 17, § 95481 (defining biogas, biomethane, and all LCFS fuels produced from biomethane).

[209] CAL. HEALTH & SAFETY CODE § 38562(b)(2). See also *Ass'n of Irritated Residents v. State Air Res. Bd.*, 206 Cal. App. 4th 1487, 1489 (2012).

[210] CAL. HEALTH & SAFETY CODE § 38562.

communities," the state board shall consider social costs.[211] CARB is currently out of compliance with each of these mandates and, accordingly, must cease and desist operation of the LCFS factory farm gas pathways unless and until it comes into compliance.

Section 38562(b)(2)'s charge to protect "low-income communities" includes "persons and families whose income does not exceed 120 percent of the area median income, adjusted for family size [...] in accordance with adjustment factors adopted and amended from time to time by the United States Department of Housing and Urban Development pursuant to Section 8 of the United States Housing Act of 1937."[212] Area median income covers "the median family income of a geographic area of the state."[213] The residents of the San Joaquin Valley are precisely the low-income communities Sections 38562 seek to protect. As demonstrated above, the LCFS factory farm gas pathways have a disproportionate adverse impact on the basis of race and income, demonstrating CARB's failure to have designed the regulations in a manner that is equitable.

Finally, 38562(b)(2) requires consideration of overall societal benefits. CARB must amend the LCFS regulation to account for this and remedy these violations to come into compliance with AB 32. In Section 38562.5 of California Health and Safety Code, social costs means "an estimate of the economic damages, including, but not limited to, changes in net agricultural productivity; impacts to public health; climate adaptation impacts, such as property damages from increased flood risk; and changes in energy system costs, per metric ton of greenhouse gas emission per year."[214] The greenhouse gas emissions and associated co-pollutants from the production of factory farm gas has significant socials costs to public health, as discussed extensively in parts III and IV(B). Amending the LCFS to account for a serious consideration of the social costs of the emissions associated with both factory farm gas and the conventional fuels that generate deficits would not only bring CARB into compliance with Section 38562.5, but it would assist CARB in understanding and evaluating the inequitable distribution of adverse impacts in a manner that supports civil rights compliance, a described above.

V. CARB'S LACK OF TRANSPARENCY DENIES THE PUBLIC THE ABILITY TO REVIEW AND CHALLENGE EXISTING REGULATIONS, INCLUDING THE LCFS PATHWAYS FOR BIOMETHANE FROM DAIRY AND SWINE MANURE.

Meaningful public participation and advocacy regarding the impacts of the LCFS program have been hindered by CARB's lack of transparency. Locations of facilities purchasing the credits generated by factory farm dairies in the San Joaquin Valley are unknown to the public and attempts to obtain trading data through the California Public Records Act has produced only heavily redacted records. Without readily available trading data, it is difficult to determine potential disparate impacts caused by both the incentives produced by credit generation and the offsetting role of credit trading within the LCFS program. Community groups and advocates should not have

[211] CAL. HEALTH & SAFETY CODE § 38562.5. Note that the 2018 amendments made the LCFS generate reductions beyond the statewide limit.
[212] CAL. HEALTH & SAFETY CODE § 50093.
[213] *Id.*
[214] CAL. HEALTH & SAFETY CODE § 38506.

to seek out this information to conduct their own analyses of CARB's potentially discriminatory policies. CARB's control over the trading data places the agency in the best position to assess the disparate impact produced by the LCFS. Moreover, CARB has a clear, affirmative duty to comply with AB 32, CA 11135, and Title VI and prevent a disparate impact from its policies and practices.

VI. CONCLUSION

Since the Legislature enacted AB 32 in 2006, both the predicted and actual climate change-related harms have become more dire.[215] The methane generated by factory farm dairies in California alone accounts for approximately 45 percent of the state's total methane emissions that contribute to these harms.[216] And the Intergovernmental Panel on Climate Change recently declared a climate code red when it called for strong, sustained, and rapid methane reductions to stabilize our climate.[217]

CARB must grant this petition and reform the LCFS. Rather than allow factory farm gas reductions to substitute for emissions increases from the transportation sector, CARB should amend the LCFS to exclude factory farm gas from this pollution trading scheme.[218] If CARB instead decides to continue allowing Big Oil & Gas to offset their transportation fuel emissions with factory farm gas, then CARB must (1) ensure that the LCFS does not inflict disparate impacts in violation of CA 11135, CA 12955, and Title VI of the Civil Rights Act; and (2) adopt all alternative LCFS amendments requested here to ensure LCFS integrity and protections for rural communities.

CARB must take this opportunity to reform a pollution trading scheme that has gone off the rails. The LCFS incentivizes more of that which it purports to control, allows inflated and illusory credits from factory farm gas to authorize more emissions from transportation fuel, refuses to acknowledge the truth that liquefied manure is intentionally created and not somehow naturally occurring awaiting only abatement, and authorizes non-additional credits generated at projects receiving massive incentives from public funds and the Aliso Canyon settlement agreement. This pollution trading scheme merely shifts emissions; it benefits Big Oil & Gas to allow more pollution from their transportation fuels. It benefits, entrenches, and expands the industrial dairy and pig industry with a revenue stream more valuable than milk. And it benefits the gas utilities that

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[215] *See, e.g.*, Thomas Fuller and Christopher Flavelle, *A Climate Reckoning in Fire-Stricken California*, N.Y. TIMES (Sept. 10, 2020), https://www.nytimes.com/2020/09/10/us/climate-change-california-wildfires.html; Christopher Flavelle, *How California Became Ground Zero for Climate Disasters*, N.Y. TIMES (Sept. 20, 2020), https://www.nytimes.com/2020/09/20/climate/california-climate-change-fires.html; Nadja Popovich, *How Severe Is the Western Drought? See For Yourself.*, N.Y. TIMES (Sept. 20, 2020), https://www.nytimes.com/interactive/2021/06/11/climate/california-western-drought-map.html.

[216] CAL. AIR RES. BD., Short-Lived Climate Pollutant Reduction Strategy 56, Figure 4 (March 2017), https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

[217] IPCC, *Climate Change 2021: the Physical Science Basis, which represents the findings of Working Group I and its contribution to the Sixth Assessment Report*, *available at* https://www.ipcc.ch/report/ar6/wg1/.

[218] Petitioners do not suggest that methane from industrial dairy and pig facilities should be unabated. CARB has authority to adopt mandatory regulations to achieve up to a 40 percent reduction from manure methane emissions pursuant to Health & Safety Code § 39730.5.

desperately attempt to perpetuate the combustion of gas in the face of a future where electrified buildings and transportation are the only routes to achieve California's climate goals. San Joaquin Valley communities should not suffer the discriminatory effects of CARB's pollution trading scheme, and CARB should grant this petition and deliver environmental justice.

Respectfully Submitted this 27th of October, 2021,

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I. APPENDICES

A. APPENDIX A: PROPOSED AMENDMENTS TO THE LCFS TO REMOVE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE

§ 95488.3. Calculation of Fuel Pathway Carbon Intensities

(a) Calculating Carbon Intensities. Fuel pathway applicants and the Executive Officer will evaluate all pathways based on life cycle greenhouse gas emissions per unit of fuel energy, or carbon intensity, expressed in gCO2e/MJ. For this analysis, the fuel pathway applicant must use CA-GREET3.0 model (including the Simplified CI Calculators derived from that model) or another model determined by the Executive Officer to be equivalent or superior to CA-GREET3.0.

(b) CA-GREET3.0. The CA-GREET3.0 model (August 13, 2018) contains emission factors for calculating greenhouse gas emissions from site-specific inputs to fuel pathways and standard values for parts of the life cycle not included in applicant-specific data submission. The model is open source and publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and is incorporated herein by reference. CA-GREET3.0 includes contributions from the Oil Production Greenhouse Gas Estimator (OPGEE2.0) model (for emissions from crude extraction) and Global Trade Analysis Project (GTAP-BIO) together with the Agro-Ecological Zone Emissions Factor (AEZ-EF) model for land use change (LUC).

Tier 1 Simplified CI Calculators, which incorporate emission factors and life cycle inventory data from the CA-GREET3.0 model, are used to calculate carbon intensities for Tier 1 pathways. The eight Simplified CI Calculators listed below are publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and are incorporated herein by reference:

(1) Tier 1 Simplified CI Calculator for Starch and Fiber* Ethanol (August 13, 2018)

(2) Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol (August 13, 2018)

(3) Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel (August 13, 2018)

(4) Tier 1 Simplified CI Calculator for LNG and L-CNG from North American Natural Gas (August 13, 2018)

(5) Tier 1 Simplified CI Calculator for Biomethane from North American Landfills (August 13, 2018)

(6) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge (August 13, 2018)

~~(7) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste (August 13, 2018)~~

© OPGEE2.0. The OPGEE2.0 model is used to generate carbon intensities for crude oil used in the production of ultra-low sulfur diesel (ULSD) and California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).

(d) Accounting for Land Use Change. The Executive Officer calculates LUC effects for certain crop-based biofuels using the GTAP model (modified to include agricultural data and termed GTAP-BIO) and the AEZ-EF model. LUC values for six feedstock/finished biofuel combinations are provided in Table 6 below. The Executive Officer may use the same modeling framework to assess LUC values for other fuel or feedstock combinations, not currently found in Table 6, as part of processing a pathway application. Alternatively, the Executive Officer may require a fuel pathway applicant to use one of the values in Table 6, if the Executive Officer deems that value appropriate to use for a fuel or feedstock combination not currently listed in Table 6.

Table 6. Land Use Change Values for Use in CI Determination

Biofuel	LUC (gCO<2>/MJ
Corn Ethanol	19.8
Sugarcane Ethanol	11.8
Soy Biomass-Based Diesel	29.1
Canola Biomass-Based Diesel	14.5
Grain Sorghum Ethanol	19.4
Palm Biomass-Based Diesel	71.4

* Fiber in this case refers to corn and grain sorghum fiber exclusively.

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(f) Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion ~~may~~ shall not be certified.~~ With a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:~~

~~(A) A biogas control system, or digester, is used to capture biomethane from manure management on~~ **~~dairy~~** ~~cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.~~

~~(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.~~

B. APPENDIX B: PROPOSED AMENDMENTS TO REFORM THE LCFS PATHWAYS FOR BIOMETHANE FROM DAIRY AND SWINE MANURE

§ 95488.3. Calculation of Fuel Pathway Carbon Intensities

(a) Calculating Carbon Intensities. Fuel pathway applicants and the Executive Officer will evaluate all pathways based on life cycle greenhouse gas emissions per unit of fuel energy, or carbon intensity, expressed in gCO2e/MJ. For this analysis, the fuel pathway applicant must use CA-GREET3.0 model (including the Simplified CI Calculators derived from that model) or another model determined by the Executive Officer to be equivalent or superior to CA-GREET3.0.

(b) CA-GREET3.0. The CA-GREET3.0 model (August 13, 2018) contains emission factors for calculating greenhouse gas emissions from site-specific inputs to fuel pathways and standard values for parts of the life cycle not included in applicant-specific data submission. The model is open source and publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and is incorporated herein by reference. CA-GREET3.0 includes contributions from the Oil Production Greenhouse Gas Estimator (OPGEE2.0) model (for emissions from crude extraction) and Global Trade Analysis Project (GTAP-BIO) together with the Agro-Ecological Zone Emissions Factor (AEZ-EF) model for land use change (LUC).

Tier 1 Simplified CI Calculators, which incorporate emission factors and life cycle inventory data from the CA-GREET3.0 model, are used to calculate carbon intensities for Tier 1 pathways. The eight Simplified CI Calculators listed below are publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and are incorporated herein by reference:

(1) Tier 1 Simplified CI Calculator for Starch and Fiber* Ethanol (August 13, 2018)

(2) Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol (August 13, 2018)

(3) Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel (August 13, 2018)

(4) Tier 1 Simplified CI Calculator for LNG and L-CNG from North American Natural Gas (August 13, 2018)

(5) Tier 1 Simplified CI Calculator for Biomethane from North American Landfills (August 13, 2018)

(6) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge (August 13, 2018)

(7) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste (August 13, 2018)

(c) OPGEE2.0. The OPGEE2.0 model is used to generate carbon intensities for crude oil used in the production of ultra-low sulfur diesel (ULSD) and California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).

(d) Accounting for Land Use Change. The Executive Officer calculates LUC effects for certain crop-based biofuels using the GTAP model (modified to include agricultural data and termed GTAP-BIO) and the AEZ-EF model. LUC values for six feedstock/finished biofuel combinations are provided in Table 6 below. The Executive Officer may use the same modeling framework to assess LUC values for other fuel or feedstock combinations, not currently found in Table 6, as part of processing a pathway application. Alternatively, the Executive Officer may require a fuel pathway applicant to use one of the values in Table 6, if the Executive Officer deems that value appropriate to use for a fuel or feedstock combination not currently listed in Table 6.

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Grain Sorghum Ethanol	19.4
Palm Biomass-Based Diesel	71.4

* Fiber in this case refers to corn and grain sorghum fiber exclusively.

<u>(e) Accounting for life cycle emissions for all fuel pathways from manure feedstock. In calculating the carbon intensity of any fuel derived from manure feedstock, the Executive Officer shall include all upstream and downstream greenhouse gas emissions from all activities associated with manure production, including but not limited to feed emissions, mobile and stationary source combustion emissions, enteric emissions, emissions from composting digestate solids, emissions following land application, and indirect source emissions.</u>

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(f) Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:

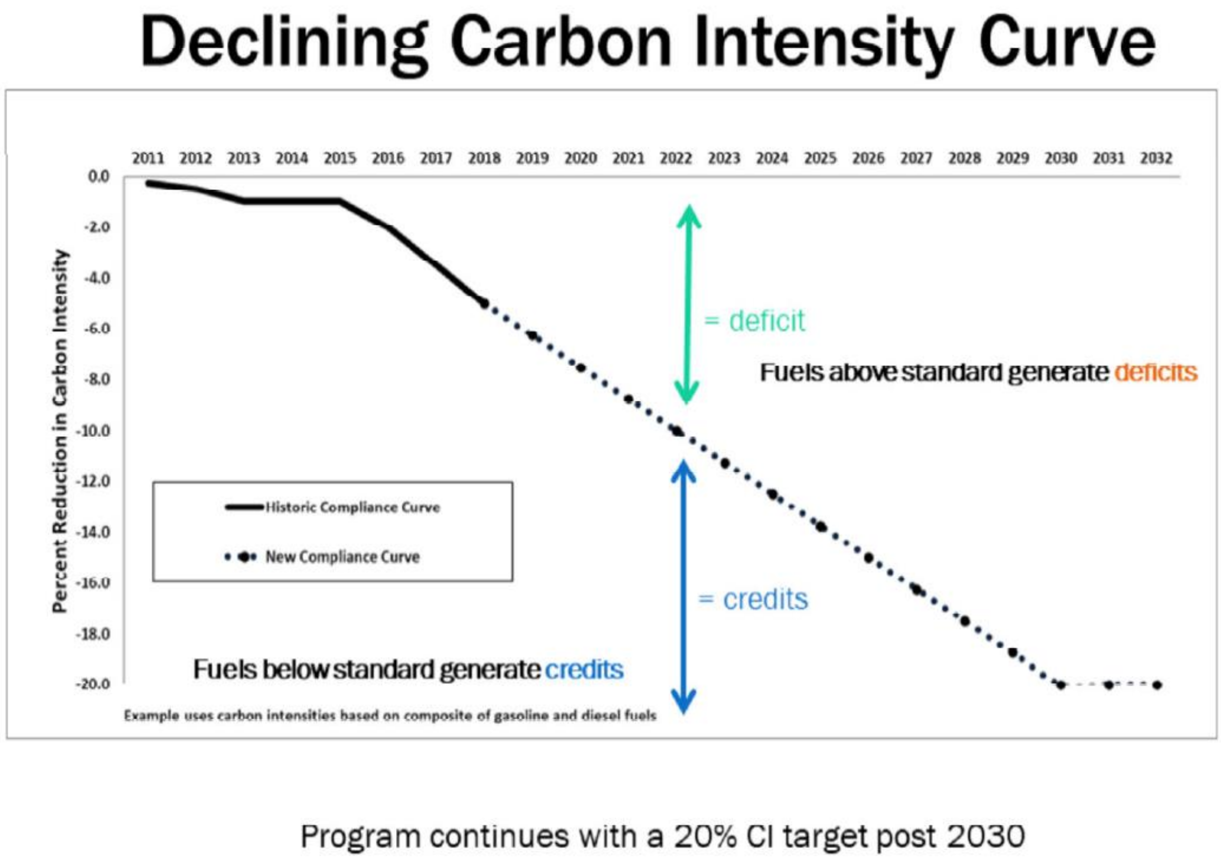
(A) A biogas control system, or digester, is used to capture biomethane from manure management on dairy cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.

(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane, and any other greenhouse gas emission reduction that otherwise would occur.

(C) The fuel pathway derived from biomethane from dairy cattle or swine manure digestion pursuant to section 95488.3(e) does not (1) contribute any amount of nitrogen oxides, volatile organic compounds, sulfur oxides, ammonia, or particulate matter with an aerodynamic diameter of ten microns or less into the ambient air; (2) cause or contribute to groundwater or surface water pollution or degradation; (3) intensify water demand in areas medium and high priority water basins; or (4) intensify or exacerbate any negative local impacts including but not limited to odor and insects.

C. APPENDIX C: TABLES AND FIGURES

Figure 1: Declining Annual Benchmark for the LCFS program.[219]



[219] CAL. AIR RES. BD., *LCFS Basics* (2019), *available at* https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited Oct. 12, 2021).

Table 1. Credit Value Calculator from LCFS Data Dashboard.[220]

Credit Value Calculator:
Estimated LCFS Premium at Sample LCFS Credit Prices

Alternative Fuel Premiums at Sample LCFS Credit Prices
($/gal gasoline-equivalent for fuels used as gasoline substitutes)

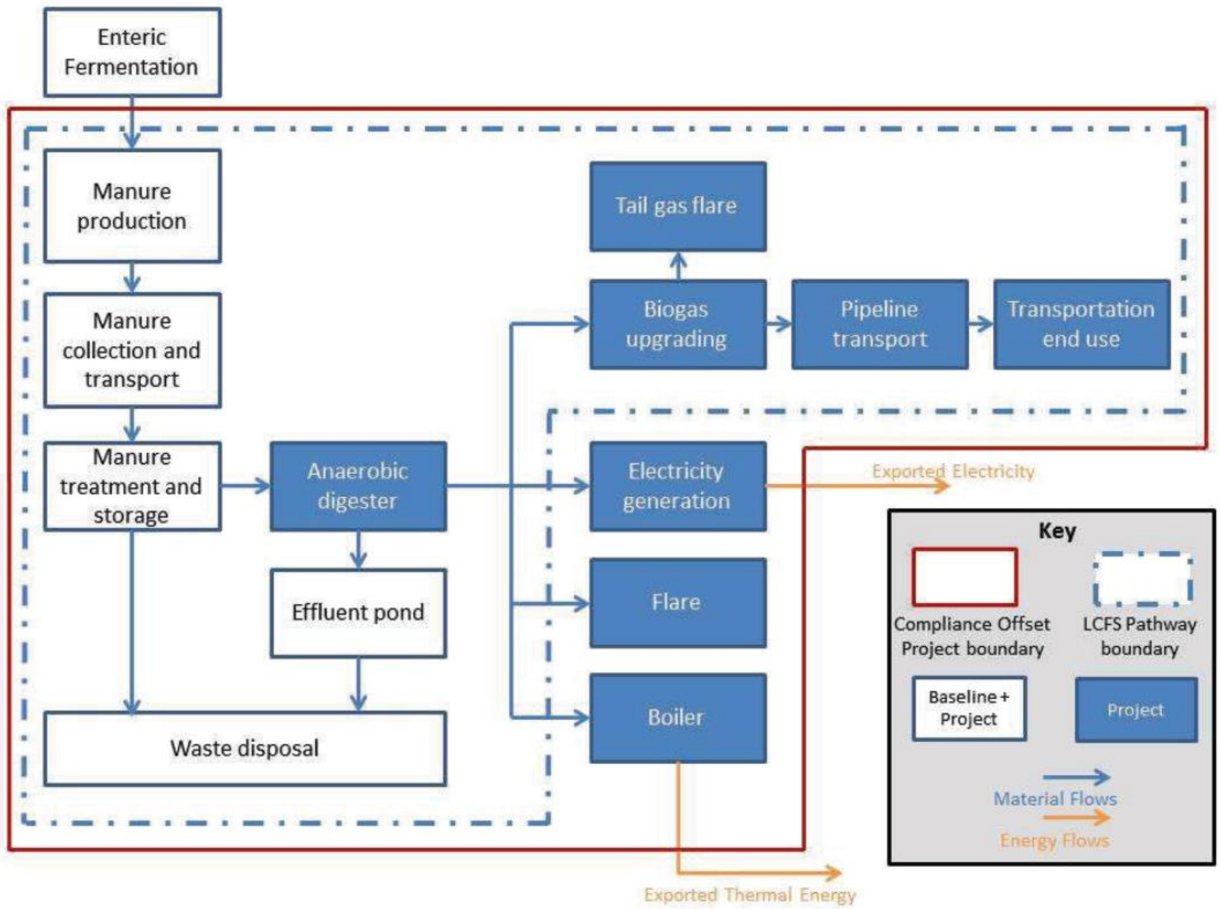
		Credit Price					
	CI Score (gCO2e/MJ)	$196	$80	$100	$120	$160	$200
	-273	$8.31	$3.39	$4.24	$5.09	$6.79	$8.48
	10	$1.89	$0.77	$0.96	$1.16	$1.54	$1.93
	20	$1.66	$0.68	$0.85	$1.02	$1.36	$1.70
	30	$1.44	$0.59	$0.73	$0.88	$1.17	$1.46
	40	$1.21	$0.49	$0.62	$0.74	$0.99	$1.23
	50	$0.98	$0.40	$0.50	$0.60	$0.80	$1.00
	60	$0.75	$0.31	$0.38	$0.46	$0.62	$0.77
	70	$0.53	$0.22	$0.27	$0.32	$0.43	$0.54
	80	$0.30	$0.12	$0.15	$0.18	$0.25	$0.31
	90	$0.07	$0.03	$0.04	$0.04	$0.06	$0.07
	100	-$0.15	-$0.06	-$0.08	-$0.09	-$0.13	-$0.16
	110	-$0.38	-$0.16	-$0.19	-$0.23	-$0.31	-$0.39
	120	-$0.61	-$0.25	-$0.31	-$0.37	-$0.50	-$0.62
	130	-$0.83	-$0.34	-$0.43	-$0.51	-$0.68	-$0.85
	140	-$1.06	-$0.43	-$0.54	-$0.65	-$0.87	-$1.08
	150	-$1.29	-$0.53	-$0.66	-$0.79	-$1.05	-$1.32
CaRFG* ($/gallon)	100.82	-$0.139	-$0.057	-$0.071	-$0.085	-$0.113	-$0.142

* Maximum pass-through cost for gasoline. Assumes a blend of CARBOB with 10 volume percent ethanol at a CI of 79.9 g/MJ. Ethanol at 79.9 g/MJ is assumed to receive no LCFS premium.

Last Modified 05/31/2019

[220] Data Dashboard, CAL. AIR RES. BD. Figure 7, *https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm* (last visited Oct. 20, 2021).

Figure 2. CARB schematic of the system boundaries for upgraded biogas (biomethane) from Anaerobic digestion of Dairy Manure.[221]



[221] CAL. AIR RES. BD., *supra* note 96 at 13.

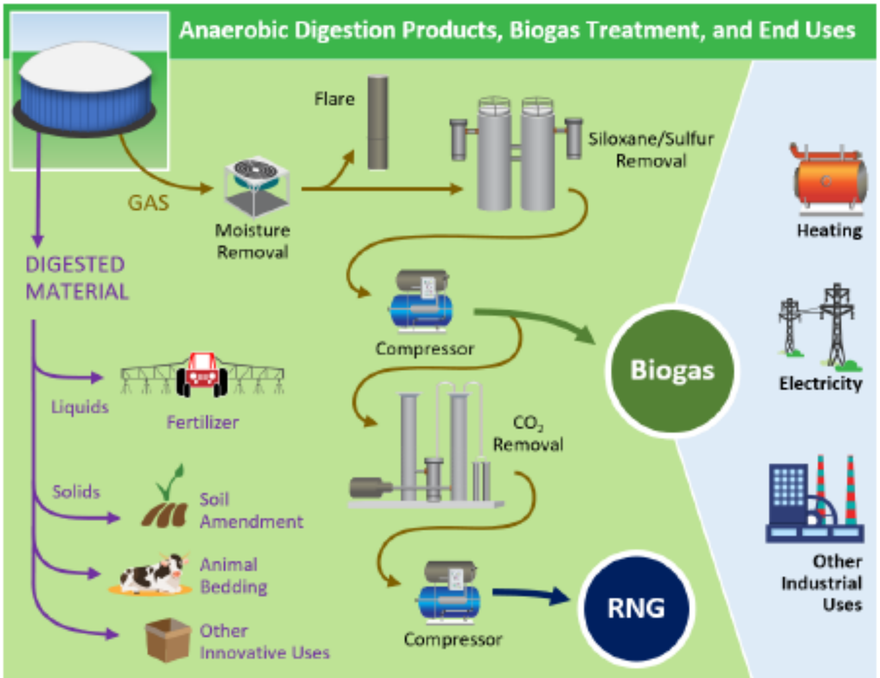
Figure 3. Waste Management Hierarchy chart for manure management.[222]

Waste Management Hierarchy	Attribute	Applicability in animal manure management
Avoidance	Most preferred option. Preventive. Use of less hazardous materials in the design and manufacture of products. Develop strategies for cleaner and environmentally friendly production	While the production of wastes cannot be completely eliminated in animal production, the production can be made cleaner and environmentally friendly
Reduction of wastes	Second most preferred option. Preventive. Actions to make changes in the type of materials being used for specific products. This approach contributes to effective savings of natural resources	Applicable
Reuse	Predominantly ameliorative and partly preventive. The waste is collected during the production phase and fed back into the production process. Reduce the amount of wastes generated and the cost of production. Desirable.	Applicable
Recycle	Predominantly ameliorative and partly preventive. The waste materials are collected and processed, and used in the production of new products. The process prevents pollution. Desirable.	Applicable
Energy recovery	Predominantly assimilative and partly ameliorative. This is also called waste to energy conversion. Wastes are converted to usable energy forms such as heat, light, electricity, etc. Desirable.	Applicable
Treatment	Predominantly assimilative and partly ameliorative. Desirable.	Applicable
Sustainable disposal	Disposal is the least preferred option in the waste management hierarchy and should be avoided.	Possible but not preferred

[222] Gabriel Adebayo Malomo et al., *Sustainable Animal Manure Management Strategies and Practices*, 9 (Aug. 29, 2018) https://www.intechopen.com/books/agricultural-waste-and-residues/sustainable-animal-manure-management-strategies-and-practices.

Figure 4. Diagram of downstream uses of digested materials.[223]

Figure 3. AD Products, Biogas Treatment and End Uses



[223] ENV'T. PROT. AGENCY, *An Overview of Renewable Natural Gas from Biogas* 4 (July 2020) https://www.epa.gov/sites/production/files/2020-07/documents/lmop_rng_document.pdf.

Figure 5. Rise in Average Monthly Credit Price since 2013.[224]

Table 2. The California dairy industry experienced negative average residuals in 2015 and 2016, indicating a lack of profit in these years.[225]

Table 1.6: California Dairy Farm Annual Unit Costs of Production by Category 2014-2017

Dairy Input	2014 $/cwt	2015 $/cwt	2016 $/cwt	2017 $/cwt
Feed	$11.05	$10.46	$9.22	$8.77
Hired Labor	$1.56	$1.70	$1.74	$1.87
Herd Replacement	$1.37	$2.12	$2.10	$1.88
Operating Costs	$2.88	$2.93	$2.92	$3.06
Milk Marketing	$0.56	$0.56	$0.55	$0.55
Total Costs	**$17.42**	**$17.77**	**$16.53**	**$16.13**
Average Mailbox Price	**$22.37**	**$15.94**	**$15.56**	**$16.99**
Price – Costs (Residual)	**$4.95**	**-$1.83**	**-$0.97**	**$0.86**

Source: CDFA California Dairy Cost of Production Annuals
https://www.cdfa.ca.gov/dairy/dairycop_annual.html

[224] AcMoody, *supra* note 128 at 4.
[225] Matthews, *supra* note 130 at 20.

Figure 6. Groundwater contamination sites in Kern County.[226]

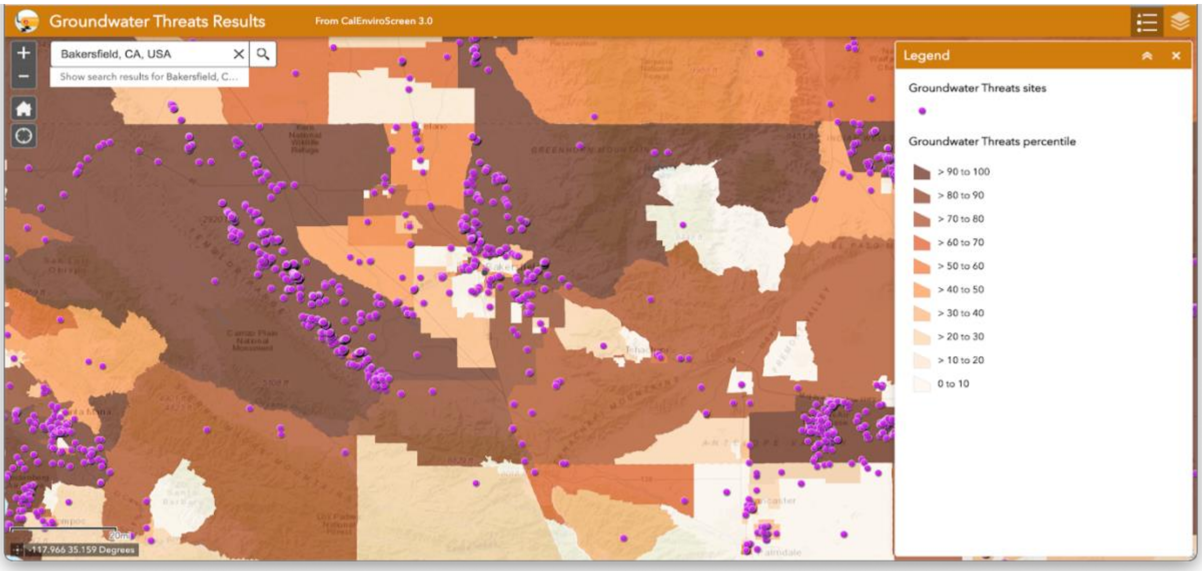
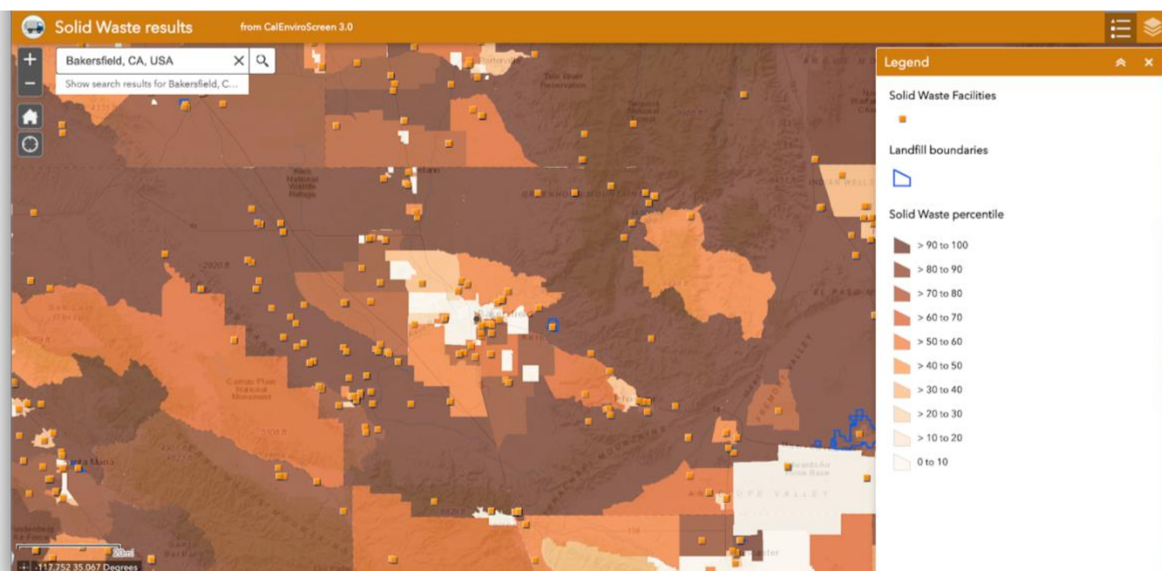
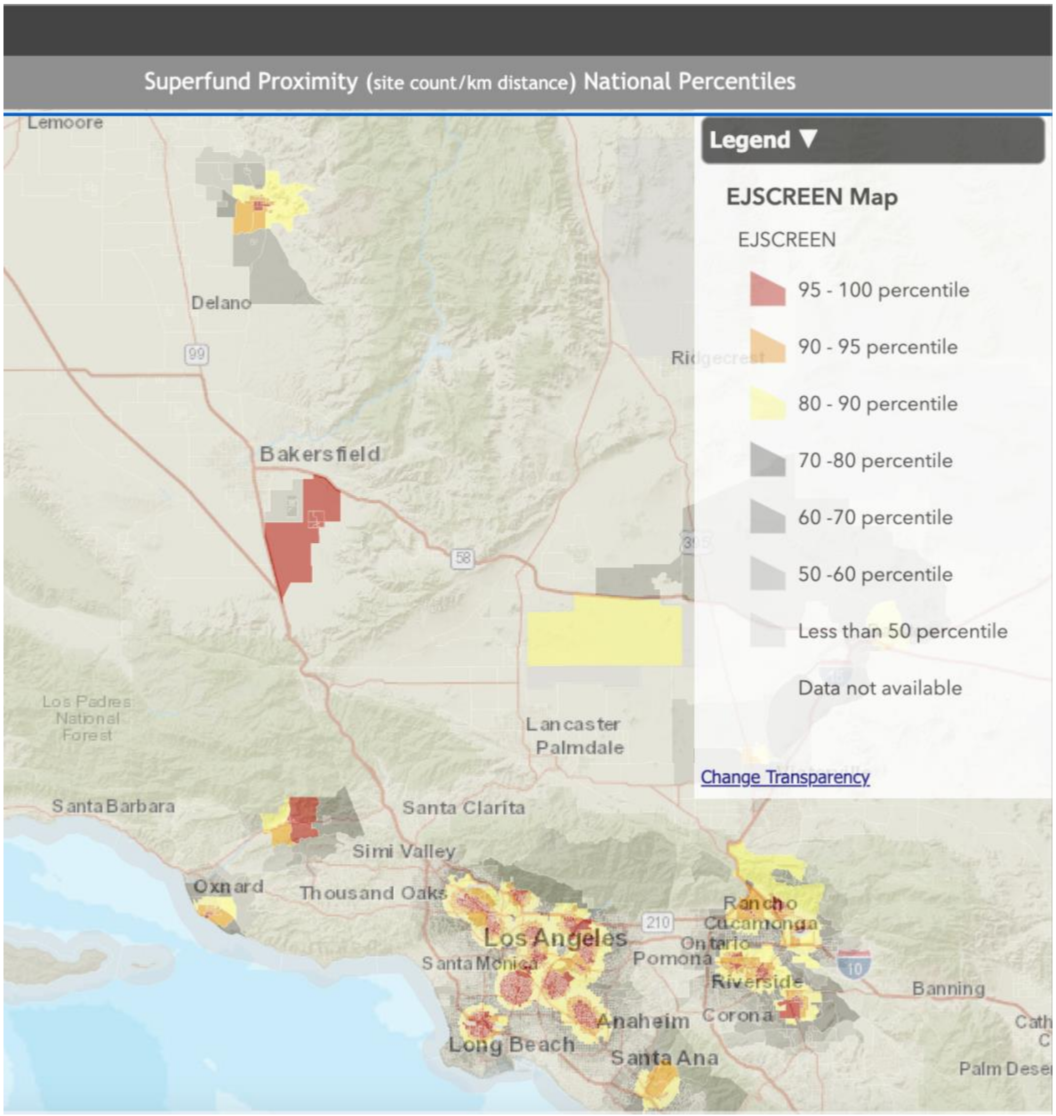


Figure 7. Solid waste contamination in Kern County.[227]



[226] CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, *supra* note 29.
[227] *Id.*

Figure 8. Superfund site near Bakersfield, CA.[228]



[228]*EJScreen*, ENV'T. PROT. AGENCY, https://www.epa.gov/ejscreen (last accessed Apr. 10, 2021).

Table 3. A list of the top counties that sell cow's milk ($ billions), the majority of which are in California.[229]

Top Counties in Cow's Milk Sales ($ billions)	
Tulare, CA	1.8
Merced, CA	1.1
Gooding, ID	0.7
Stanislaus, CA	0.7
Kings, CA	0.6
Kern, CA	0.5
Yakima, WA	0.4
Lancaster, PA	0.4
Fresno, CA	0.4
San Joaquin, CA	0.4

Does not include counties withheld to avoid disclosing individual data.

[229] U.S. DEP'T OF AGRIC., *Dairy Cattle and Milk Production* at 2 (Oct. 2014) https://www.nass.usda.gov/Publications/Highlights/2014/Dairy_Cattle_and_Milk_Production_Highlights.pdf.

Table 4. Demographic data on Kern, Kings, Madera, and San Joaquin Counties.[230]

Fact	Kern County, California	Kings County, California	Madera County, California	San Joaquin County, California
Population estimates, July 1, 2019, (V2019)	900,202	152,940	157,327	762,148
Population estimates base, April 1, 2010, (V2019)	839,621	152,974	150,834	685,306
Population, percent change - April 1, 2010 (estimates base) to	7.20%	0.00%	4.30%	11.20%
Population, Census, April 1, 2010	839,631	152,982	150,865	685,306
Persons under 5 years, percent	7.60%	7.60%	7.30%	6.90%
Persons under 18 years, percent	28.80%	27.00%	27.40%	26.80%
Persons 65 years and over,	11.20%	10.50%	14.30%	13.10%
Female persons, percent	48.80%	44.90%	51.80%	50.10%
White alone, percent	82.30%	80.80%	85.90%	66.10%
Black or African American alone,	6.30%	7.50%	4.20%	8.30%
American Indian and Alaska Native alone, percent	2.60%	3.20%	4.40%	2.00%
Asian alone, percent	5.40%	4.40%	2.60%	17.40%
Native Hawaiian and Other Pacific Islander alone, percent	0.30%	0.40%	0.30%	0.80%
Two or More Races, percent	3.20%	3.70%	2.60%	5.50%
Hispanic or Latino, percent	54.60%	55.30%	58.80%	42.00%
White alone, not Hispanic or Latino, percent	32.80%	31.30%	33.20%	30.50%
Veterans, 2015-2019	35,594	9,684	6,317	29,013
Foreign born persons, percent,	19.90%	18.90%	20.20%	23.30%
Housing units, July 1, 2019,	302,898	46,965	51,438	248,636
Owner-occupied housing unit rate, 2015-2019	58.30%	52.30%	64.10%	56.60%
Median value of owner-occupied housing units, 2015-2019	213,900	215,900	251,200	342,100
Median selected monthly owner costs -with a mortgage, 2015-2019	$1,527	$1,459	$1,551	$1,907
Median selected monthly owner costs -without a mortgage, 2015-	$452	$446	$478	$523
Median gross rent, 2015-2019	$978	$990	$1,014	$1,208
Building permits, 2019	2,261	409	644	3,499
Households, 2015-2019	270,282	43,452	44,881	228,567
Persons per household, 2015-	3.17	3.13	3.28	3.17
Living in same house 1 year ago, percent of persons age 1 year+,	86.10%	81.90%	87.90%	86.80%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	44.20%	41.50%	45.30%	40.90%
High school graduate or higher, percent of persons age 25 years+,	74.10%	73.40%	71.90%	79.30%
Bachelor's degree or higher, percent of persons age 25 years+,	16.40%	14.70%	14.60%	18.80%
With a disability, under age 65 years, percent, 2015-2019	7.80%	8.60%	8.70%	8.70%
Persons without health insurance, under age 65 years,	9.00%	8.50%	10.70%	7.80%
In civilian labor force, total, percent of population age 16	58.00%	51.80%	54.30%	60.30%
In civilian labor force, female, percent of population age 16	52.40%	51.50%	47.90%	53.60%
Total accommodation and food services sales, 2012 ($1,000)	1,092,151	378,595	150,065	808,606
Total health care and social assistance receipts/revenue,	3,675,000	587,818	760,956	3,447,722
Median household income (in 2019 dollars), 2015-2019	$53,350.00	$57,848.00	$57,585.00	$64,432.00
Per capita income in past 12 months (in 2019 dollars), 2015-	$23,326.00	$22,373.00	$22,853.00	$27,521.00
Persons in poverty, percent	19.00%	16.00%	17.60%	13.60%

[230] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/US/PST045219 (last visited Apr. 10, 2021).

Table 5. Demographic data on Merced, Tulare, Fresno, and Stanislaus Counties.[231]

Fact	Merced County, California	Tulare County, California	Fresno County, California	Stanislaus County, California
Population estimates, July 1, 2019, (V2019)	277,680	466,195	999,101	550,660
Population estimates base, April 1, 2010, (V2019)	255,796	442,182	930,507	514,450
Population, percent change - April 1, 2010 (estimates base) to July 1, 2019, (V2019)	8.60%	5.40%	7.40%	7.00%
Population, Census, April 1, 2010	255,793	442,179	930,450	514,453
Persons under 5 years, percent	7.70%	7.80%	7.60%	7.10%
Persons under 18 years, percent	29.30%	30.50%	28.20%	27.00%
Persons 65 years and over, percent	11.40%	11.60%	12.60%	13.40%
Female persons, percent	49.50%	50.00%	50.10%	50.40%
White alone, percent	82.20%	88.20%	76.60%	83.30%
Black or African American alone, percent	3.90%	2.20%	5.80%	3.50%
American Indian and Alaska Native alone, percent	2.50%	2.80%	3.00%	2.00%
Asian alone, percent	7.80%	4.00%	11.10%	6.10%
Native Hawaiian and Other Pacific Islander alone, percent	0.40%	0.20%	0.30%	0.90%
Two or More Races, percent	3.20%	2.70%	3.20%	4.20%
Hispanic or Latino, percent	61.00%	65.60%	53.80%	47.60%
White alone, not Hispanic or Latino, percent	26.50%	27.70%	28.60%	40.40%
Veterans, 2015-2019	9,225	14,633	36,125	21,051
Foreign born persons, percent, 2015-2019	26.30%	21.80%	21.20%	20.30%
Housing units, July 1, 2019, (V2019)	86388	151603	336473	182978
Owner-occupied housing unit rate, 2015-2019	52.20%	57.10%	53.30%	57.80%
Median value of owner-occupied housing units, 2015-2019	252,700	205,000	255,000	291,600
Median selected monthly owner costs -with a mortgage, 2015-2019	1,493	1,420	1,631	1,702
Median selected monthly owner costs -without a mortgage, 2015-2019	$460.00	$421.00	$484.00	$503.00
Median gross rent, 2015-2019	$1,021.00	$942.00	$998.00	$1,155.00
Building permits, 2019	948	1,872	3,393	699
Households, 2015-2019	80,008	138,238	307,906	173,898
Persons per household, 2015-2019	3.32	3.3	3.14	3.09
Living in same house 1 year ago, percent of persons age 1 year+, 2015-2019	86.60%	88.60%	85.80%	87.90%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	53.30%	51.30%	44.60%	42.90%
High school graduate or higher, percent of persons age 25 years+, 2015-2019	69.10%	70.80%	76.00%	78.90%
Bachelor's degree or higher, percent of persons age 25 years+, 2015-2019	13.80%	14.60%	21.20%	17.10%
With a disability, under age 65 years, percent, 2015-2019	9.10%	8.20%	9.20%	9.00%
Persons without health insurance, under age 65 years, percent	9.00%	9.00%	8.80%	7.10%
In civilian labor force, total, percent of population age 16 years+, 2015-2019	59.60%	59.00%	60.90%	60.90%
In civilian labor force, female, percent of population age 16 years+, 2015-2019	51.00%	51.10%	55.20%	53.40%
Total accommodation and food services sales, 2012 ($1,000)	232,910	451,880	1,226,169	705,698
Total health care and social assistance receipts/revenue, 2012 ($1,000)	788114	1610236	5325615	3634960
Median household income (in 2019 dollars), 2015-2019	$53,672.00	$49,687.00	$53,969.00	$60,704.00
Per capita income in past 12 months (in 2019 dollars), 2015-2019	$23,011.00	$21,380.00	$24,422.00	$26,258.00
Persons in poverty, percent	17.00%	18.90%	20.50%	13.00%

[231] *Id.*

Table 6. Quick facts on potential pathogens found in digestate and links for further information.[232]

Pathogen	**Effects**	**For more information**
Cryptosporidium parvum	"[M]icroscopic parasite that causes the diarrheal disease cryptosporidiosis."	https://www.cdc.gov/parasites/crypto/index.html
Salmonella spp	"Most people with Salmonella infection have diarrhea, fever, and stomach cramps."	https://www.cdc.gov/salmonella/general/index.html
norovirus	"Norovirus is a very contagious virus that causes vomiting and diarrhea."	https://www.cdc.gov/norovirus/index.html
Streptococcus pyogenes	"[C]an cause both noninvasive and invasive disease, as well as nonsuppurative sequelae. "	https://www.cdc.gov/groupastrep/diseases-hcp/index.html
E. coli enteropathogenic (EPEC)	"[A]re gram-negative bacteria that inhabit the gastrointestinal tract. Most strains do not cause illness. Pathogenic E. coli are categorized into pathotypes on the basis of their virulence genes. Six pathotypes are associated with diarrhea	https://wwwnc.cdc.gov/travel/yellowbook/2020/travel-related-infectious-diseases/escherichia-coli-diarrheagenic

232 *Parasites – Cryptosporidium (also known as "Crypto")*, CDC, https://www.cdc.gov/parasites/crypto/index.html (last updated July 1, 2019); *Salmonella*, CDC, https://www.cdc.gov/salmonella/general/index.html (last updated Dec 5, 2019); *Norovirus*, CDC, https://www.cdc.gov/norovirus/index.html (last updated Mar. 5, 2021); *Group A Streptococcal (GAS) Disease*, CDC, https://www.cdc.gov/groupastrep/diseases-hcp/index.html (last updated May 7, 2020); Alison Winstead et al., *Escherichia coli, Diarrheagenic*, CDC, https://wwwnc.cdc.gov/travel/yellowbook/2020/travel-related-infectious-diseases/escherichia-coli-diarrheagenic (last updated July 1, 2021); J. L. Cloud et al., *Identification of Mycobacterium spp. by Using a Commercial 16S Ribosomal DNA Sequencing Kit and Additional Sequencing Libraries*, 40(2) J. Clinical Microbiology 400, 400 (Feb. 2002); *Typhoid Fever and Paratyphoid Fever*, CDC, https://www.cdc.gov/typhoid-fever/index.html (last updated Aug. 22, 2018); *Fact Sheet: Clostridium spp*, WickhamLaboratories, https://wickhamlabs.co.uk/technical-resource-centre/fact-sheet-clostridium-spp/ (last visited May 5, 2021); Listeria (Listeriosis), CDC, https://www.cdc.gov/listeria/symptoms.html (Dec. 12, 2016).

	(diarrheagenic) […] enteropathogenic E. coli (EPEC)”	
Mycobacterium spp.	"Mycobacterium species are a group of acid-fast, aerobic, slow-growing bacteria. The genus comprises more than 70 different species, of which about 30 have been associated with human disease (23)."	https://www.ncbi.nlm.nih.gov/pmc/articles/PMC153382/#:~:text=Mycobacterium%20species%20are%20a%20group,the%20causative%20agent%20of%20tuberculosis
Salmonella typhi (followed by S. paratyphi)	"Typhoid fever and paratyphoid fever are life-threatening illnesses caused by Salmonella serotype Typhi and Salmonella serotype Paratyphi, respectively."	https://www.cdc.gov/typhoid-fever/index.html
Clostridium spp.	“Clostridia are one of the most commonly studied anaerobes that cause disease in humans”. Some of the species of Clostridium can cause: botulism, overgrow in the intestine compromising the inherent gut flora (potentially leading to colitis), tetanus, gas gangrene (myonecrosis), and toxic shock syndrome.	https://wickhamlabs.co.uk/technical-resource-centre/fact-sheet-clostridium-spp/
Listeria monocytogenes	"[C]an cause fever and diarrhea similar to other foodborne germs, but this type of Listeria infection is rarely diagnosed. Symptoms in people with invasive listeriosis, meaning the bacteria has spread beyond the gut, depend on whether the person is pregnant."	https://www.cdc.gov/listeria/symptoms.html

Attach. 2

TOLLING AGREEMENT

This Tolling Agreement ("Agreement") is entered into effective November 29, 2021, between ASSOCIATION OF IRRITATED RESIDENTS, FOOD & WATER WATCH, LEADERSHIP COUNSEL FOR JUSTICE & ACCOUNTABILITY, and ANIMAL LEGAL DEFENSE FUND (collectively, "Petitioners") and the CALIFORNIA AIR RESOURCES BOARD ("CARB").

RECITALS

WHEREAS, on October 27, 2021, Petitioners filed the PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM ("Petition"), pursuant to Government Code § 11340.6.

WHEREAS, CARB acknowledged receipt of the Petition in a written letter to Petitioners sent on November 8, 2021.

WHEREAS, Government Code section 11340.7(a) provides thirty (30) days for CARB to respond to the merits of the Petition.

WHEREAS, on November 18, 2021, CARB requested that Petitioners enter into a 60-day tolling agreement to toll the deadline under Government Code section 11340.7(a) to allow CARB additional time to respond to the Petition and to provide time for Petitioners and CARB to reach common ground on matters alleged in the Petition.

WHEREAS, on November 24, 2021, Petitioners agreed to a 60-day tolling agreement to allow CARB additional time to respond to the Petition to conserve resources and potentially allow Petitioners and CARB to reach common ground.

WHEREAS, this Agreement memorializes the agreement reached by Petitioners and CARB on November 24, 2021.

NOW THEREFORE, in consideration of the mutual terms, covenants, conditions and promises contained herein, the Petitioners and CARB hereto agree as follows.

TERMS

1. All of the foregoing recitals are incorporated herein by reference.

2. Subject to any subsequent agreements between Petitioners and CARB, CARB shall respond to the Petition by January 28, 2022.

3. CARB and Petitioners shall engage in good faith discussions in an effort to reach common ground with respect to the issues raised in the Petition between November 29, 2021, and January 28, 2022.

4. Any statutes of limitations to challenge CARB's response to the Petition pursuant to Government Code § 11340.7(a) shall be tolled as of November 24, 2021, and shall be tolled until January 28, 2022.

CALIFORNIA AIR RESOURCES BOARD

Gabriel Monroe, Attorney for CARB

12/06/2021

ASSOCIATION OF IRRITATED RESIDENTS

Tom Frantz, President

12/06/2021

FOOD AND WATER WATCH

Tyler Lobdell, Staff Attorney

12/6/21

LEADERSHIP COUNSEL for JUSTICE AND ACCOUNTABILITY

Phoebe Seaton, Attorney for Leadership Counsel for Justice and Accountability

12/6/21

ANIMAL LEGAL DEFENSE FUND

Christine Ball-Blakely, Staff Attorney

Christine Ball-Blakely

12/6/21

Attach. 3

January 07, 2022

Submitted via ca.gov

Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Public Workshop: Potential Future Changes to the LCFS Program

Dear Chair Randolph and CARB Staff,

The Association of Irritated Residents, Leadership Counsel for Justice & Accountability, Animal Legal Defense Fund, Food & Water Watch, and Public Justice (collectively "Commenters") thank you for hosting the December 7th, 2021, public workshop and for the opportunity to submit comments regarding changes to the LCFS program. On October 27, 2021, Commenters submitted the Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program ("Petition"), provided here as Attachment A. The Petition lays out critical changes that CARB must implement to effectively reform the LCFS; first and foremost, by excluding factory farm "biogas" from the LCFS entirely. As presently implemented, the LCFS is incentivizing and rewarding the intentional and avoidable production of GHGs at factory farms, which in turn entrenches some of the worst practices used by factory farms that pollute air and water at the local, regional, and global levels. The wildly inflated and illusory factory farm gas credits that CARB certifies undermine the integrity of the LCFS program and contribute to the unlawful disproportionate impacts on California's lower income communities and communities of color from both the factory farm industry as well as increased emissions from dirty transportation fuel providers.

Commenters submit the Petition for the record here and respectfully ask that CARB promptly initiate rulemaking in response. Numerous parties expressed opposition to CARB's suggestion that any LCFS rulemaking must wait for finalization of the 2022 Scoping Plan, and Commenters join that chorus. Waiting until 2024 or beyond to implement reforms to the LCFS in response to the Petition is unacceptable, unnecessary, and would constitute an abuse of discretion. Therefore, we request that CARB immediately initiate rulemaking in response to the Petition.

Commenters also request that CARB staff stay certification of factory farm gas tier 2 applications at least until CARB provides its formal response to the Petition and during any subsequent rulemaking. Commenters continue to oppose these applications because certification will lock in the market distortions and disproportionate impacts explained in detail in the Petition, violating both California and federal law. CARB is under no obligation to certify such applications by a date certain, and the serious flaws in the LCFS program's treatment of factory farm gas warrant delay while CARB addresses these program failures.

Thank you again for this opportunity to comment on potential changes to the LCFS. We look forward to CARB's response to the Petition and attendant rulemaking.

Respectfully,

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Leadership Counsel for Justice & Accountability

Tom Frantz
Association of Irritated Residents

Christine Ball-Blakely
Animal Legal Defense Fund

Tyler Lobdell
Food & Water Watch

Brent Newell
Public Justice

Attachment A: Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program

BEFORE THE CALIFORNIA AIR RESOURCES BOARD

PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM

PETITION FOR RULEMAKING

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I. INTRODUCTION

The California Air Resources Board (CARB) allows inflated and non-additional credits derived from factory farm gas[1] to undermine the integrity of the Low Carbon Fuel Standard (LCFS) pollution trading scheme and exacerbate discriminatory environmental and public health harms in the San Joaquin Valley. The LCFS increases harmful pollution to air, water, and land in rural low-income and Latina/o/e communities; inflates factory farm gas reductions by excluding upstream and downstream emissions; allows non-additional reductions from other factory farm gas incentive programs to generate credits; fails to achieve reductions from transportation fuels when these inflated and non-additional factory farm credits justify excessive fossil fuel emissions; and perversely incentivizes increased greenhouse gas emissions and pollution from dairy and pig factory farms.

To remedy these deficiencies, the Association of Irritated Residents (AIR), Leadership Counsel for Justice & Accountability, Food & Water Watch, and Animal Legal Defense Fund petition the CARB for rulemaking to amend the LCFS to exclude all fuels derived from factory farm gas. In the alternative, CARB must reform the LCFS program to account for the full life cycle of factory farm gas emissions – including all upstream and downstream emissions from activities and inputs at dairy and pig facilities – and exclude non-additional emissions reductions that occur as a result of other factory farm gas incentives, including the Dairy Digester Research Development Program. CARB must also take steps to ensure that its policies and practices do not impose discriminatory harms on low-income and Latina/o/e communities in the San Joaquin Valley.

In 2006, the California Legislature determined that climate change posed "a serious threat to the economic well-being, public health, natural resources, and the environment of California."[2] To address these threats, CARB designed a range of programs that would monitor, regulate, and ultimately reduce greenhouse gas emissions, including the LCFS.[3] But as written and as implemented, the LCFS pathways for factory farm gas do not effectively reduce greenhouse gas emissions, violating CARB's obligation to achieve the maximum cost-effective and technologically feasible emissions reductions.

The LCFS intentionally promotes factory farm gas, a fusion of Big Ag and Big Oil & Gas, two of the industries most responsible for the climate crisis and whose entire business model relies on extraction and exploitation. Big Ag brought us polluted wells, foul air, antibiotic-resistant pathogens, methane-spewing manure lagoons, and workplace conditions that caused rampant outbreaks of COVID-19. Big Ag has driven family farmers off their farms, stripped wealth from our communities, and gutted our rural main streets. Big Oil & Gas brought us countless oil spills, tanker wrecks, pipeline explosions, and climate damage. There is no reason to entrust our future to the very industries responsible for the harms the LCFS seeks to address.

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[1] Factory farm gas refers to the fuel the LCFS designates "biomethane from the anaerobic digestion of dairy and swine manure."
[2] CAL. HEALTH & SAFETY CODE § 38501.
[3] CAL. HEALTH & SAFETY CODE § 38510.

The results of CARB's embrace of these false solutions to the benefit of Big Ag and Big Oil & Gas are clear: due to the LCFS's deficient accounting of the emissions from factory farm gas, the program encourages increased production of the liquified manure necessary to generate factory farm gas, resulting in *more* intentionally created methane from new and expanding dairy and pig facilities. By propping up factory farm gas, the LCFS provides a new way for big corporations to get rich off a problem they created. In CARB's accounting of the carbon intensity of factory farm gas, the LCFS fails to include the full quantity of associated upstream and downstream greenhouse gas emissions, leading to an exaggerated negative carbon intensity value and a corresponding inflation of LCFS credit prices for factory farm gas. The resulting inflated credits do not encourage emissions reductions, instead, they reward factory farms for the production of toxic manure as though it were a cash crop. This "hot air" in the credit market, along with the award of credits for reductions from other incentive programs that would have occurred anyway, undermines the LCFS framework by allowing transportation fuel producers to emit more climate pollution based on illusory reductions.

No amount of corporate public relations spin, greenwashing, or deficient carbon intensity calculations can hide the fact that factory farm gas is created from massive harm. By incentivizing increased manure production and liquification, the LCFS program also fails to maximize additional environmental benefits in violation of the *Global Warming Solutions Act of 2006* (AB 32), and even increases the well-documented environmental and public health harms caused by pig and dairy factory farms. These facilities release enormous quantities of solid, liquid, and gaseous waste. In addition to greenhouse gas emissions, the waste from both pigs and dairy cows releases various co-pollutants including ammonia, hydrogen sulfide, volatile organic compounds (VOCs), and severe odor. The factory farm system relies on disposing the manure nitrogen on crops, which also leads to both nitrous oxide emissions and nitrate contamination of groundwater. Experience tells us that racism, exploitation, and extraction are embedded in the factory farm system – we know these harms are disproportionately imposed on Black, Indigenous, People of Color, and low-income communities around the country. In California, these harms discriminatorily impact low-income and Latina/o/e communities in the San Joaquin Valley in violation of state and federal law.[4]

CARB has an affirmative duty under Government Code section 11135 (CA 11135) and Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d, to ensure that its policies and practices do not have a discriminatory impact on the basis of race.[5] CARB has an affirmative duty under AB 32 to ensure that "activities undertaken to comply with the regulations do not disproportionately impact low-income communities" and to design regulations in a manner that is equitable.[6] Finally, Government Code section 12955 (CA 12955) prohibits any practice or program that has a discriminatory effect on members of protected classes with respect to housing opportunities, including with respect to the use and enjoyment of dwellings.[7] Furthermore, the

[4] Addressing discriminatory impacts resulting from the LCFS's inclusion of factory farm gas in other parts of the country where dairy and pig factory farms are concentrated is beyond the scope of this petition. However, CARB should also evaluate these potential impacts, given that the program includes applicants from around the country. CAL. AIR RES. BD., *LCFS Pathways Requiring Public Comments*, https://ww2.arb.ca.gov/resources/documents/lcfs-pathways-requiring-public-comments#t2.

[5] CAL. GOV'T CODE § 11135; 42 U.S.C. § 2000d.

[6] CAL. HEALTH & SAFETY CODE § 38562(b).

[7] CAL. GOV'T CODE § 12955.8; CAL. CODE REGS. TIT. 2 § 12161.

accountability our democracy depends on the public knowing the truth: who is benefiting, where the money is coming from, who is defining the problem, who is being impacted, and how they are harmed by the LCFS. By failing to even conduct a transparent disparity analysis of this highly-technical program, CARB impedes the public's ability to fairly evaluate CARB's choice to prop up Big Ag and Big Oil & Gas.

A people's government – our government – protects and serves the people's interests. It invests in food and climate solutions that create a healthy future for our children and grandchildren. It invests in good jobs that strengthen our rural communities. But CARB has created and implemented a pollution trading scheme that benefits polluters rather than uses the power granted by the people of California to prevent harms. On top of decades of discriminatory impacts in the San Joaquin Valley, California is facing the dire impacts of the climate crisis. We cannot afford a scheme that serves corporate interests over the people's needs.

To remedy these harms and to bring the LCFS regulation into compliance with state and federal law, the petitioners request that CARB amend section 95488.9 of the LCFS to exclude any "fuel pathway that utilizes biomethane from dairy and swine manure digestion."[8] In the alternative, petitioners request that CARB amend the LCFS regulation to (a) ensure that the life cycle analysis for biomethane from dairy and swine manure is expanded to include a full accounting of life cycle emissions; (b) amend section 95488.9 to ensure additionality of reductions; (c) properly classify methane from swine and dairy factory farms as intentionally occurring; (d) ensure compliance with state and federal civil rights law, including but not limited to conducting disparity analyses of LCFS pathways and credit trading; and (e) ensure the LCFS provides environmental benefits and does not degrade water quality and interfere with efforts to improve air quality in the San Joaquin Valley.

II. BACKGROUND

A. THE LCFS PROGRAM

AB 32 set a statewide target to reduce California's greenhouse gas emissions to 1990 levels by 2020.[9] In 2007, Governor Arnold Schwarzenegger issued Executive Order S-01-07, which directed CARB to adopt the LCFS pollution trading scheme to diversify California's transportation fuels and curb dependence on petroleum.[10] The California Office of Administrative Law approved the LCFS regulation in 2010 and the regulation has since undergone four rounds of amendments.[11]

According to CARB, "[T]he LCFS is designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce

[8] CAL. CODE REGS. TIT. 17 § 95488.9.
[9] CAL. HEALTH & SAFETY CODE § 38550.
[10] CAL. EXEC. DEP'T, Exec. Order No. S-01-07, (Jan. 22, 2007), *available at* https://www.library.ca.gov/Content/pdf/GovernmentPublications/executive-order-proclamation/5107-5108.pdf; *see also generally,* CAL. HEALTH & SAFETY CODE § 38560.5 (requiring CARB to establish GHG reduction measures).
[11] CAL. CODE REGS. TIT. 17 § 95480 et seq.

greenhouse gas emissions and decrease petroleum dependence in the transportation sector."[12] The LCFS, like similar pollution trading schemes, constructs a market where credits and deficits that represent emissions in relation to a declining baseline can be traded. These tradeable LCFS credits provide a new revenue stream for producers of fuels that have been deemed low-carbon intensity with the goal of incentivizing increased production and displacing the use of more greenhouse gas-intensive fuels. The LCFS requires entities that produce conventional transportation fuels to report the carbon intensity of these fuels, while certain alternative fuel producers may opt into the program and demonstrate their fuel's carbon intensity in their application.[13]

Every year, CARB sets progressively lower benchmarks for the carbon intensity of fuels.[14] Transportation fuels with carbon intensity values above the annual benchmark generate deficits, and transportation fuels with carbon intensity values below the benchmark generate credits (see Figure 1, Appendix C).[15] While obligated parties are required to either meet the benchmark or purchase credits to offset the extra emissions associated with their fuel, voluntary parties that produce alternative, low-CI fuels are incentivized to participate because fuels with carbon intensities below the benchmark generate revenue through the sale of LCFS credits.[16]

The LCFS regulation defines "carbon intensity" as "the quantity of life cycle greenhouse gas emissions, per unit of fuel energy, expressed in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ)."[17] The emissions included in each fuel's carbon intensity calculation are usually bounded by "fuel pathways," defined as "the collective set of processes, operations, parameters, conditions, locations, and technologies throughout all stages that CARB considers appropriate to account for in the system boundary of a complete well-to-wheel analysis of [a given] fuel's life cycle greenhouse gas emissions."[18] Accurate and thorough life cycle analyses for each fuel and the accurate accounting of the baseline against which each fuel's carbon intensity is compared are independent and necessary preconditions for the program to identify which fuels to encourage to decrease net greenhouse gas emissions.

The LCFS classifies fuel pathways into three groups: Lookup Table, Tier 1, and Tier 2 pathways.[19] Regulated parties can register their fuels using the standard pathways in the Lookup

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[12] *Low Carbon Fuel Standard: About,* CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Oct. 12, 2021).
[13] CAL. CODE REGS. TIT. 17 §§ 95483-95483.1.
[14] CAL. CODE REGS. TIT. 17 § 95484.
[15] *Id.*
[16] CARB accounts for credits and implements credit transfers with the LCFS Reporting Tool and Credit Bank & Transfer System. CAL. AIR RES. BD., *LCFS Registration and Reporting*, https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-registration-and-reporting (last visited Oct. 12, 2021).
[17] CAL. CODE REGS. TIT. 17 § 95481(a)(26). "Life Cycle Greenhouse Gas Emissions," in turn, is defined as "the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions, such as significant emissions from land use changes) as determined by the Executive Officer, related to the full fuel life cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential. CAL. CODE REGS. TIT. 17 § 95481(a)(88).
[18] CAL. CODE REGS. TIT. 17 § 95481(a)(66).
[19] CAL. CODE REGS. TIT. 17 § 95488.1(a).

Table if the fuel produced “closely corresponds” to a Lookup Table pathway.[20] Tier 1 and Tier 2 pathways are open to voluntary applicants, including those seeking credit for factory farm gas. Tier 1 is for “the most common low carbon fuels” and uses a Simplified CI calculator, where Tier 2 is for “innovative, next generation fuel pathways,” and uses the full CA-GREET3.0 model.[21] Tier 1 includes fuels like ethanol and biomethane anaerobic digesters of dairy and swine manure, among others.[22] Tier 2 includes fuels from sources not in Tier 1 as well as pathways included in Tier 1 that use “innovative production methods.”[23] The majority of factory farm gas producers apply for Tier 2 pathways rather than the Tier 1 pathway.

Ten years after enacting AB 32, the California Legislature set a new target for greenhouse gas emissions in Senate Bill 32 (SB 32) – 40 percent below 1990 levels.[24] The Legislature stipulated, however, that SB 32 would only be operative if it also enacted Assembly Bill 197 (AB 197), which amended AB 32 in several ways.[25] AB 197 added Section 38562.5, which required that regulations promulgated to achieve emissions reductions beyond the statewide greenhouse gas limit, including the LCFS, consider the social costs of greenhouse gases, prioritize direct emissions reductions, and incorporate the requirements of Section 38562(b).[26] These requirements include crucial mandates to design the regulations in a manner that is equitable; ensure that activities taken to comply with the regulations “do not disproportionately impact low-income communities” and “do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions;” and consider the overall societal benefits, including reductions in other air pollutants and other benefits to the environment.[27]

B. THE SAN JOAQUIN VALLEY

California’s San Joaquin Valley, as discussed in this petition, refers to eight counties that compose the valley floor from San Joaquin County in the north, to Kern County in the south. While disadvantaged communities within the region confront air pollution, toxic emissions, and unsafe drinking water at rates and degrees disproportionate to other communities in the state, the San Joaquin Valley is also home to resilient, diverse communities and networks that have worked together over decades to promote robust mutual aid networks, expand civic engagement, and lead

[20] CAL. CODE REGS. TIT. 17 § 95488.5(a)(1)-(6) (“Closely corresponds” means that the applicant’s fuel pathway and a pathway on the Lookup Table are consistent in feedstock, production technology, the region in which the feedstock and fuel is produced, transport distance (if applicable), types and amount of thermal and electrical energy used in feedstock and finished fuel production, and that the CI of the entity’s product is lower than or equal to the CI of the pathway in the lookup table.)

[21] CAL. AIR RES. BD., LCFS Guidance 19-01, Book and Claim Accounting for Low-CI Electricity 2, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-01.pdf. While Tier 1 applicants provide a “discrete set of inputs” based on the specifics of their operations to be used by one of the pre-existing Tier 1 Simplified CI Calculators, Tier 2 applicants must conduct and submit a full life cycle analysis using the CA-GREET3.0 model for their own customized pathway. CAL. CODE REGS. TIT. 17 § 95488.3.

[22] CAL. CODE REGS. TIT. 17 § 95488.1(c).

[23] CAL. CODE REGS. TIT. 17 § 95488.1(d).

[24] CAL. HEALTH & SAFETY CODE § 38566.

[25] SB 32, 2016 CAL. LEGIS. SERV. CH. 249.

[26] AB 197, 2016 CAL. LEGIS. SERV. CH. 250.

[27] CAL. HEALTH & SAFETY CODE §§ 38562(2), (4), (6).

efforts from the household to the community level to model climate resilience and environmental stewardship.

The region is known for and, to a great extent, characterized by industrial agricultural operations, including large confined animal feeding operations. Decades of similar investment, land use, and economic development strategies have failed and continue to fail to prioritize the economic well-being and health of San Joaquin Valley residents, leading to severe income inequality, poverty, and environmental degradation despite the inherent assets of the region.

The "disadvantaged communities" of California, as defined pursuant to Senate Bill 535, are concentrated in the San Joaquin Valley.[28] Seven of the eight counties in the Valley (all except San Joaquin County) report mean income well below the 120% limit that defines low-income.[29] Every county in the San Joaquin Valley has lower household and per capita incomes, and higher poverty rates than California as a whole.[30] While median household income in California in 2019 was $75,235, countywide household median incomes for San Joaquin Valley Counties ranged from $49,687 to $64,432. The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $53,672 and $49.687 – both at 71 percent or below statewide median income.[31] Notably, nine of ten of the most recent applications for consideration for Low Carbon Fuel Standard Tier 2 Pathways from California factory farm gas were in Tulare County and Kern County. Kern County, like Merced and Tulare, faces disproportionately high poverty rates at 19 percent. Even this data likely inflates reported income level, because it may exclude the San Joaquin Valley's thousands of undocumented residents and residents of the Valley's unincorporated communities.[32]

San Joaquin Valley residents are disproportionately Latina/o/e as compared to California as a whole. All eight San Joaquin Valley Counties have higher Latino populations than the state,[33] with populations ranging from 42 percent to 65.6 percent, as compared to the state population with

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[28] CAL. ENV'T PROT. AGENCY, *Designation of Disadvantaged Communities Pursuant to Senate Bill 535 (De León)* 1-32 (Apr. 2017), https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf.

[29] Section 39711 of the Health and Safety Code sets the ceiling for low-income communities at 120% of the area median income. Additionally, Section 39711 designates communities with disproportionate environmental impacts and concentrations of low income, high unemployment, low educational attainment, and other burdensome socioeconomic factors as disadvantaged communities. All eight counties of the San Joaquin Valley fall within these categories. *See Maps & Data,* CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Apr. 9, 2021) (flagging areas of California that exhibit high to low pollution burdening scores). *Income Limits*, U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il.html#2020_data (last updated Apr. 1, 2020) (choose 30% Income Limit for ALL Areas (Excel)); *FY 2020 State Income Limits* (2020), U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il/il20/State-Incomelimits-Report-FY20r.pdf.

[30] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[31] Poverty rates in every single county in the San Joaquin Valley also exceed poverty rates in California, with Merced, Tulare facing 17 and 18.9 percent poverty rates (as compared to 11.8 percent at the statewide level). *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[32] 310,000 people live in low-income unincorporated communities in the San Joaquin Valley – "this is 70,000 more than what the Census Bureau included in its low-income Census Designated Places in the San Joaquin Valley." POLICYLINK, *California Unincorporated: Mapping Disadvantaged Communities in the San Joaquin Valley* 9 (2013), https://www.policylink.org/sites/default/files/CA%20UNINCORPORATED_FINAL.pdf.

[33] Latino is the term used by the U.S. Census.

39.4 percent of residents classified as Latino. At least seven of eight San Joaquin Valley communities have a lower proportion of white residents as compared to the state as a whole.[34] Merced and Tulare counties have white, non-Latino populations of 26.5 and 27.7 percent, and Latino populations of 65.6 and 61 percent, respectively.[35] Like Merced and Tulare, Kern County also demonstrates much higher Latino populations than the rest of the state, with a Latino population of 54.6 percent.

The disproportionately low-income and Latina/o/e residents of the San Joaquin Valley are exposed to the worst air quality in the state by most measures and lower income communities in the San Joaquin Valley are disproportionately subject to water contaminated with nitrates, arsenic, and 1,2,3 TCP, among others. The San Joaquin Valley is classified as an area that fails to meet several federal health-based standards for fine particulate matter ($PM_{2.5}$).[36] According to the American Lung Association, the San Joaquin Valley cities of Fresno-Madera-Hanford and Bakersfield are the second and third most polluted with respect to short-term exposure to $PM_{2.5}$.[37] The Valley cities of Bakersfield, Fresno-Madera-Hanford, and Visalia are the first, second, and third most polluted with respect to long-term exposure to $PM_{2.5}$.[38] The Valley also violates health-based standards for ozone.[39] Bakersfield, Visalia, and Fresno-Madera-Hanford are the second, third, and fourth most ozone-polluted cities in the in United States.[40] The San Joaquin Valley contains about half of California's 300 public water systems that currently serve unsafe drinking water.[41] Over the past three decades, nitrate levels in drinking water have exceeded the federal maximum contaminant level of 45 mg/L NO_3 (equivalent to 10 mg/L nitrate-N) in an estimated 24 to 40% of domestic wells in different counties in the San Joaquin Valley, compared to 10 to 15% of California's overall water supply.[42]

This pollution impacts the health and well-being of San Joaquin Valley residents.[43] Short-term exposure to $PM_{2.5}$ pollution causes premature death, decreased lung function, exacerbates respiratory disease such as asthma, and causes increased hospital admissions.[44] Long-term

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[34] According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[35] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Oct. 12, 2021).

[36] 80 FED. REG. 18,528 (April 7, 2015); 81 FED. REG. 2,993 (January 20, 2016); 80 FED. REG. 2,206, 2,217 (January 15, 2015).

[37] AM. LUNG ASSN., *State of the Air 2021* 37, *available at* https://www.lung.org/getmedia/17c6cb6c-8a38-42a7-a3b0-6744011da370/sota-2021.pdf.

38 *Id.* at 38.

[39] 75 FED. REG. 24409 (May 5, 2010); 77 FED. REG. 30088, 30092 (May 21, 2012).

[40] AM. LUNG ASSN., *supra* note 37 at 36.

[41] Del Real, J.A., *They Grow the Nation's Food, but They Can't Drink the Water*, N.Y. TIMES (May 21, 2019), https://www.nytimes.com/2019/05/21/us/california-central-valley-tainted-water.html.

[42] Eli Moore, et al., *The Human Costs of Nitrate-contaminated Drinking Water in the San Joaquin Valley*, PAC. INST., 11 (2011), https://pacinst.org/publication/human-costs-of-nitrate-contaminated-drinking-water-in-the-san-joaquin-valley/.

[43] The COVID-19 pandemic has made exposure to particulate matter even more dangerous, further highlighting the health risks associated with air pollution from factory farm dairies and factory farm gas. Xiao Wu et al., *Air pollution and COVID-19 mortality in the United States: Strengths and limitations of an ecological regression analysis*, 6 SCI. ADVANCES 1 at 1-2 (Nov. 4, 2020), https://advances.sciencemag.org/content/6/45/eabd4049.

[44] AM. LUNG ASSN., *supra* note 37 at 37-38.

exposure can cause asthma and decreased lung function in children, increased risk of death from cardiovascular disease, and increased risk of death from heart attacks.[45] Nitrates in drinking water can cause serious illness and death in infants ("blue baby syndrome") and are linked to pregnancy complications and birth defects, Sudden Infant Death Syndrome, and respiratory tract infections and a number of different cancers in adults and children.[46]

CARB has acknowledged that $PM_{2.5}$ exposure alone "is responsible for about 1,200 cases of premature death in the Valley each year."[47] San Joaquin Valley residents, who CalEnviroScreen designate a "sensitive population," experience higher rates of asthma, low birth weight, and cardiovascular disease compared to state incidence rates.[48] The California Institute for Rural Studies estimates that the costs of these air quality-related health harms total over $6 billion per year in the San Joaquin Valley.[49] This pollution also impacts residents' quality of life. For example, children in the San Joaquin Valley suffer from lack of access to outdoor recreation – on days with especially poor air quality, which occurred 40 days in Kern County in 2018, local authorities recommend that schools hold recess indoors.[50]

III. CARB MUST EXCLUDE BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LCFS OR IN THE ALTERNATIVE AMEND THE REGULATION TO ACCURATELY ACCOUNT FOR THE FULL CARBON INTENSITY OF THESE FUELS AND PROHIBIT CREDITS FROM NON-ADDITIONAL REDUCTIONS.

The LCFS violates sections 38560.5, 38562(b), 38562(d)(2), 38562.5 of the Health & Safety Code because it fails to achieve the maximum technologically feasible and cost-effective emissions reductions, fails to maximize additional environmental benefits, fails to ensure additionality of reductions, and exacerbates harms associated with industrial animal agriculture, including toxic air contaminants and dangerous water pollution. These failures prevent the state from maximizing greenhouse gas emissions reductions from transportation fuels and constitute a failure to use best scientific practices, as required by section 38562(e). Moreover, they harm San

[45] *Id*. at 38-39.
[46] WIS. DEP'T OF HEALTH SERV., *Infant Methemoglobinemia (Blue Baby Syndrome)*, https://www.dhs.wisconsin.gov/water/blue-baby-syndrome.htm (last updated Mar. 12, 2021).
[47] CAL. AIR RES. BD., *Clean-air plan for San Joaquin Valley first to meet all federal standards for fine particle pollution* (Jan. 24, 2019), https://ww2.arb.ca.gov/news/clean-air-plan-san-joaquin-valley-first-meet-all-federal-standards-fine-particle-pollution.
[48] *Indicators Overview*, CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/indicators#:~:text=Sensitive%20population%20indicators%20measure%20the,of%20their%20age%20or%20health (last visited Oct. 21, 2021); *see* AM. LUNG ASSN., *supra* note 37 at 23; Ashley E. Larsen et al., *Agricultural pesticide use and adverse birth outcomes in the San Joaquin Valley of California*, 6 NATURE COMMC'N 1, AT 4-8 (2007); Amy M. Padula et al., *Traffic-Related Air Pollution and Risk of Preterm Birth in the San Joaquin Valley of California*, 24(12) ANN EPIDEMIOL 1, 6-9; *see also* Robbin Marks, Nat. Res. Def. Council, *Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health* (2001), https://www.nrdc.org/sites/default/files/cesspools.pdf.
[49] Lisa Kresge and Ron Strochlic, *Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health*, CAL. INST. FOR RURAL STUDIES 8, (Jul. 2007).
[50] Brendan Borrell, *California's Fertile Valley is Awash with Air Pollution*, MOTHERJONES (Dec. 10, 2018), https://www.motherjones.com/environment/2018/12/californias-fertile-valley-is-awash-in-air-pollution/. *See also Policies and Procedures for Poor Outdoor Air Quality Days*, SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DIST., http://www.valleyair.org/programs/ActiveIndoorRecess/intro.htm (last visited Oct. 12, 2021).

Joaquin Valley communities with increased air and water pollution from factory farm dairies subsidized by the LCFS – harms the Legislature sought to address when it enacted AB 32 and AB 197.[51] For all of these reasons, CARB should amend the LCFS to exclude all fuels derived from biomethane from swine and dairy manure.[52] If CARB fails to do so, it must at a minimum amend the regulation to capture the full life cycle of associated greenhouse gas emissions in both the established Tier 1 pathway and the customized Tier 2 pathways and amend the regulation to ensure credited reductions are additional.[53]

A. The fuel pathways for biomethane from dairy and swine manure fail to achieve the maximum technologically feasible and cost-effective emissions reductions.

AB 32 mandates that the early action measure regulations adopted by CARB "shall achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit."[54] CARB explicitly premised the adoption of the LCFS regulation on this mandate.[55] As written and in practice, however, the LCFS regulation does not incentivize, let alone achieve, the maximum emissions reductions in this sector due to the program's inflation of carbon intensity values for factory farm gas. These inflated credit values are the result of CARB's narrow interpretation of the life cycle emissions for factory farm gas. Moreover, CARB's failure to ensure that credited emissions reductions are additional to what otherwise would have occurred inject invalid credits into the overall market and allow fuel producers to emit more pollution.

By setting overly narrow system boundaries for the life cycle analysis of factory farm gas, the LCFS fails to account for emissions associated with a true "well-to-wheels" analysis, exaggerating the emissions reductions attributed to this fuel. AB 32 requires that market-based compliance mechanisms only credit "additional" emissions reductions, and thus exclude reductions already required by law or that otherwise would occur.[56] However, CARB has allowed the LCFS program to award credits generated from non-additional reductions at factory farms. Factory farm gas projects rely on multiple sources of revenue from grant programs, federal programs, and the Aliso Canyon settlement – all of this supplementary revenue renders reductions from factory farm gas projects either partially or fully non-additional, yet CARB has made no effort to prevent these non-additional credits from entering the market.

Because CARB has allowed grossly inflated carbon intensity scores to distort the market, and allowed non-additional reductions to generate credits, the LCFS perversely incentivizes bigger dairy and pig operations to generate more methane. As a result, credit revenue from dairy factory

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[51] CAL. HEALTH & SAFETY CODE § 38501 (the Legislature named the "exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems" as potential adverse impacts of climate change.)
[52] CAL. CODE REGS. TIT. 17 § 95488.3; CAL. CODE REGS. TIT. 17 § 95488.9(f)(1). *See* proposed amendments in Appendix A.
[53] *See* proposed amendments in Appendix B.
[54] CAL. HEALTH & SAFETY CODE § 38560.5.
[55] CAL. AIR RES. BD., RES. 19-27, (Nov. 21, 2019).
[56] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

farm gas can be a more reliable income stream than milk revenue, propping up this high-emissions industry and further polluting nearby communities. Additionally, the financial windfall from these over-valued credits is traded to offset emissions from LCFS deficit holders. Together and separately, each of these violations undermines the LCFS program and constitutes a failure to achieve the maximum technologically feasible and cost-effective emissions reductions from transportation fuels in violation of AB 32.

1. The fuel pathways for biomethane from dairy and swine manure fail to incorporate life-cycle emissions, leading to inflated credits.

The LCFS over-values credits awarded to factory farm gas operations because the program omits significant emissions from the factory farm gas life cycle. Neither the established Tier 1 nor the customized Tier 2 pathways for biomethane from dairy and swine manure capture the greenhouse gas emissions associated with the full life cycle of factory farm gas. The pathways ignore both upstream and downstream emissions. In addition to setting overly narrow system boundaries, the factory farm gas life cycle analyses fail to properly account for the fact that the methane purportedly captured in the production of factory farm gas is intentionally created, resulting in an even more misleading accounting of associated climate harms. When the resulting inflated credits are traded, they allow LCFS deficit holders to achieve less than the required maximum technologically feasible and cost-effective reductions.

The LCFS requires a full "well-to-wheels" life cycle analysis to account for all emissions associated with a given fuel.[57] Such well-to-wheels accounting requires Tier 2 pathways to include "a description of all fuel production feedstocks used, including all pre-processing to which feedstocks are subject."[58] Likewise, applicants must provide:

> a detailed description of the calculation of the pathway CI. This description must provide clear, detailed, and quantitative information on process inputs and outputs, energy consumption, greenhouse gas emissions generation, and the final pathway carbon intensity, as calculated using CA-GREET3.0. Important intermediate values in each of the primary life cycle stages shall be shown. *Those stages include but are not limited to feedstock production and transport*; fuel production, fuel transport, and dispensing; co-product production, transport and use; waste generation, treatment and disposal; and fuel use in a vehicle.[59]

Feedstocks are the raw materials processed into fuel. The feedstock for factory farm gas is manure. Therefore, emissions from manure production and "pre-processing" must be included in the life cycle analysis for Tier 2 applicants. But the LCFS and CARB's implementation does not require their inclusion. For example, CalBioGas Kern Cluster's recent application begins the data-listing portion of its lifecycle analysis with the Dairy Livestock Input Data table.[60] This table does not provide an adequate analysis of the feedstock production energy input. In fact, this lifecycle

[57] CAL. CODE REGS. TIT. 17 § 95481(a)(66).
[58] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(2).
[59] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(B) (emphasis added).
[60] CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

analysis contains no analysis pertaining to the emissions from the generation and processing of manure to produce the feedstock.

Accounting for the greenhouse gas emissions from the production and "pre-processing" of dairy or pig manure must include the inputs and infrastructure necessary to sustain a dairy cow or a pig: its food and water, the methane animals produce through enteric fermentation, the construction and maintenance of the lagoons required to hold manure, trucking livestock and other inputs, combustion of fuels at the dairy facility for electricity, and more. But the LCFS factory farm gas pathways only begin after the production of the manure itself, leaving out all upstream emissions generated formulating that manure.[61]

The regulation further enumerates that, "for fuels utilizing agricultural crops for feedstocks, the description [of feedstocks in the life cycle analysis report] shall include the agricultural practices used to produce those crops. This discussion shall cover energy and chemical use, typical crop yields, feedstock harvesting, transport modes and distances, storage, and pre-process (such as drying or oil extraction)."[62] In the Tier 2 pathways for ethanol production, this provision has been interpreted to include production and pre-processing of corn, the feedstock for ethanol. Similarly, the LCFS requires pathways that utilize organic material to "demonstrate that emissions are not significant beyond the system boundary of the fuel pathway," upon request.[63] Yet in the case of factory farm gas, none of the production and pre-processing of the feedstock is considered, making it an outlier in the LCFS program and out of compliance with section 95488.7.

The failure to include production and pre-processing of manure when calculating life cycle emissions is even more problematic because a common feed for dairy cows in California is distillers grains, a "co-product" of ethanol production. The designation of distillers grains as a "co-product" allows ethanol producers to split the emissions from corn production between the ethanol and distillers grains by weight, decreasing ethanol's carbon intensity in the LCFS analysis.[64] One ethanol industry blog noted that "the biggest factor for most of the low-CI scoring [ethanol] plants is the proportion of wet distillers grains sold locally."[65] Distillers grains are granted the "co-product" designation by virtue of the revenue they generate when sold as animal feed but because LCFS factory farm gas pathways do not account for production and pre-processing of manure, the emissions associated with distillers grains are never accounted for by the LCFS at all despite its

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[61] CAL. AIR RES. BD., *Compliance Offset Protocol Livestock Projects* (Nov. 14, 2014), Table 4.1, Description of all GHG Sources, GHG Sinks, and GHG Reservoirs; *see also* CAL. AIR RES. BD., Response to Animal Defense Legal Fund Comment, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/new_temp_carb_response.pdf (CARB arguing that "Emissions from existing CAFO operations are accounted for, but do not include emissions associated with enteric methane and animal feed use because these emissions should more appropriately be allocated to and associated with the preexisting underlying, non-fuel product stream, and are thus excluded from the system boundary in the Board approved Tier 1 Calculator.")

[62] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(2).

[63] CAL. CODE REGS. TIT. 17 § 95488.9(f)(2)(B).

[64] CAL. AIR RES. BD., *Tier 1 Simplified CI Calculator Instruction Manual: Starch and Fiber Ethanol* (Aug. 13, 2018), *available at* https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

[65] Susanne Retka Schill, *Meeting the California Low Carbon Challenge*, ETHANOL PROD. MAGAZINE (Feb. 8, 2016), http://ethanolproducer.com/articles/13000/meeting-the-california-low-carbon-challenge.

role in two transportation fuel life cycles.[66] Some ethanol plants also incorporate factory farm gas from dairies as a process fuel, further lowering the ethanol's carbon intensity.[67] These "negative" upstream emissions from factory farm gas and negative downstream emissions from the use of distillers grains as dairy feed both reduce the LCFS carbon intensity of ethanol, which would likely not receive credits otherwise.

While downstream emissions from distillers grains in ethanol production are accounted for by excluding them from that fuel's carbon intensity calculation, the by-product of dairy and swine factory farm gas, digestate – which would *increase* the carbon intensity of factory farm gas – remains largely unaccounted for, even though the LCFS requires all Tier 2 pathway application lifecycle analyses to include:

> a description of all co-products, byproducts, and waste products associated with production of the fuel. That description shall extend to all processing, such as drying of distiller's grains, applied to these materials after they leave the fuel production process, including processing that occurs after ownership of the materials passes to other parties.[68]

Demonstrably, any storage, land-application, or composting of digestate falls within the meaning of the term 'process,' but the LCFS does not require, and no factory farm gas lifecycle analyses include emissions from digestate.

The process of anaerobic digestion can result in "changes in the manure composition" that alter ammonia (NH_3) and nitrous oxide (N_2O) emissions, depending upon the management strategy used.[69] In the United States, liquid effluent from factory farm gas production is primarily applied to land as fertilizer and digestate solids are composted and then land applied or used for bedding on-farm (See Figure 4 in Appendix C).[70] Digestate land application and composting result in emissions of nitrous oxide, which has a global warming potential 265 to 298 times that of carbon dioxide.[71] A recent study found that digested solids that were composted released such significant

[66] Somerville, Scott, Daniel A. Sumner, James Fadel, Ziyang Fu, Jarrett D. Hart, and Jennifer Heguy, *By-Product Use in California Dairy Feed Has Vital Sustainability Implications*, ARE UPDATE 24(2) (2020) 5, University of California Giannini Foundation of Agricultural Economics.

[67] For example, a Tier 2 ethanol pathway for a plant in Pixley, California uses biomethane from dairies as a process fuel to transform starch from corn into ethanol. *GFP Ethanol, LLC dba Calgren Renewable Fuels GREET Pathway for the Production of Ethanol from Corn and Fueled by NG and Biogas from Two Local Dairy Digesters* (Sept. 20, 2018), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/t2n-1279_report.pdf.

[68] CAL. CODE REGS. TIT. 17 § 95488.7(a)(2)(A)(8).

[69] Michael A. Holly et al., *Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture*, 239 ECOSYSTEMS AND ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007.

[70] Ron Alexander, *Digestate Utilization in The U.S.*, 53 BIO CYCLE 56 (Jan. 2012), https://www.biocycle.net/digestate-utilization-in-the-u-s/. Mohanakrishnan Logan & Chettiyappan Visvanathan, *Management strategies for anaerobic digestate of organic fraction of municipal solid waste: Current status and future prospects*, 37 WASTE MGT. & RES. 27, 27 (Jan. 28, 2019), https://doi.org/10.1177/0734242X18816793.

[71] Holly, *supra* note 69 at 411. Alun Scott & Richard Blanchard, *The Role of Anaerobic Digestion in Reducing Dairy Farm Greenhouse Gas Emissions*, 13 SUSTAINABILITY 2 (Mar. 1, 2021) https://doi.org/10.3390/su13052612; *Understanding Global Warming Potentials*, ENV'T PROT. AGENCY, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials (last visited Oct. 21, 2021).

nitrous oxide emissions relative to undigested manure solids that the climate benefits of the captured methane from the digestion process were cancelled out.[72] Additionally, many operators choose to store digestate in open-air lagoons. Open-air storage can release methane, potentially negating methane captured during digestion, as well as ammonia, which is harmful to nearby communities in the San Joaquin Valley and a $PM_{2.5}$ precursor.[73]

Despite the significant emissions associated with digestate and the high global warming potential of methane and nitrous oxide, the LCFS fails to fully account for this inevitable by-product of factory farm gas production. Digestate treatment and storage is within the Tier 1 system boundary for anaerobic digestion of dairy and swine manure (described as "effluent"), but the pathway does not contemplate emissions associated with effluent after storage.[74] In contrast to Tier 1, the Tier 2 system boundary in the CA GREET3.0 calculator includes emissions from "AD Residue Applied to Soil," in other words, digestate that is land applied.[75] In practice, however, digestate is not mentioned in several recent Tier 2 applications for cluster projects.[76] Further, in responding to a comment criticizing a project's lack of accounting for digestate emissions, the applicant responded in a letter to CARB that "land application of effluent is outside of the scope of the project."[77] These contradictory descriptions of the system boundary as related to digestate highlight an inconsistent approach to the quantification of emissions from digestate. Moreover, neither the pathways nor the project application materials seem to account for digestate uses other than land application. This excludes any emissions associated with the solids composting. By failing to account for downstream emissions associated with land application and the massive nitrous oxide emissions from solids composting, CARB's life cycle analysis omits significant greenhouse gas emissions from factory farm gas production and further inflates the factory farm gas credit value.

The factory farm gas life cycle analyses also fail to include downstream emissions associated with transport. The LCFS factory farm gas pathways mention, but do not require reporting of inputs to calculate emissions generated from the refining and transport of factory farm gas. For example, the Tier 1 Calculator for factory farm gas *can* quantify emissions leaked or

72 Holly, *supra* note 69 at 414, 418.
73 *See generally* Yun Li et al., *Manure digestate storage under different conditions: Chemical characteristics and contaminant residuals*, 639 SCI. OF THE TOTAL ENV'T 19 (Oct. 15, 2018), https://doi.org/10.1016/j.scitotenv.2018.05.128 (discussing the impacts of open storage).
74 CAL. AIR RES. BD., Tier 1 Simplified CI Calculator Instruction Manual: Biomethane from Anaerobic Digestion of Dairy and Swine Manure (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.63225775.1254208748.1633995805-239480191.1598055085.
75 *LCFS Life Cycle Analysis Models and Documentation: California GREET3.0 Model,* CAL. AIR RES. BD., https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation (last visited July 29, 2021).
76 *See* CAL. AIR RES. BD., *Fuel Pathway Table: Current Fuel Pathways*, *available at* https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities (last visited Oct. 19, 2021).
77 Letter from Michael D. Gallo, Gallo Cattle Company Regarding "Tier 2 Pathway Application: Application No. B0089" (June 26, 2020), on file with CAL. AIR RES. BD., https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/b0089_response.pdf.

vented from the digester and associated pipeline infrastructure—but the applicant is not *required* to calculate it.[78]

In addition to the failure to account for various upstream and downstream emissions from factory farm gas production, the LCFS life cycle analyses do not address the fact that these emissions are associated with *intentionally created* methane. LCFS factory farm gas pathways are intended to credit "reduction[s] of greenhouse gas emissions achieved by the voluntary capture of methane" or "avoided methane emissions."[79] This structure is premised on the idea that the manure used to produce the gas is unavoidable waste, whose emissions would not otherwise be diverted. But the massive quantity of manure methane emissions that CARB seeks to mitigate is the result of the intentional liquification of the manure, one of multiple manure management methods. While necessary to produce factory farm gas, the production of vast quantities of liquified manure is by no means an inevitable result of dairy or pig farming.[80] Alternative manure management techniques are available. Techniques such as solid-liquid separation, scrape and vacuum collection of manure, composting, and pasture-based practices are all viable methods of manure management that would avoid the methane emissions caused by open-air lagoons of liquid manure. Preliminary findings from CARB's Dairy and Livestock Greenhouse Gas Emissions Working Group indicate that these methods of manure management may offer more cost-effective methane emissions reductions than anaerobic digestion and may deliver additional environmental and health benefits, such as reduced impact on water quality.[81] Avoiding manure generation and reducing the amount of manure that has to be managed is the best way to protect human and animal health, along with the environment (see Figure 3 in Appendix C on Waste Management Hierarchy).[82] But the LCFS program does the opposite of promoting dairy manure avoidance or even lower-emissions manure management practices. Instead, the LCFS program has created a new revenue stream for factory farms based on the manure itself – the source of the methane the program seeks to reduce – incentivizing the production and liquification of manure as though it were a cash crop.

Additionally, "even RNG from waste methane can have negative climate impacts relative to the most likely alternative of flaring, not venting, the methane."[83] Flaring, like other forms of combustion, converts methane to carbon dioxide, reducing the net emissions impact. Flaring is a ubiquitous, low cost means of reducing methane. Though flaring is not a sustainable means to

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[78] CAL. AIR RES. BD., *Tier 1 Simplified CI Calculator Instruction Manual: Biomethane from Anaerobic Digestion of Dairy and Swine Manure* 1, 8–9, 13–14 (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.153600376.1744114239.1608082460-1114251839.1598731081.
[79] CAL. CODE REGS. TIT. 17 § 95488.9(f).
[80] *Animal Agriculture in the U.S. – Trends in Production and Manure Management*, LIVESTOCK AND POULTRY ENV'T LEARNING CMTY. (Mar. 5, 2019), https://lpelc.org/animal-agriculture-in-the-u-s-trends-in-production-and-manure-management/.
[81] CAL. AIR RES. BD., *Findings and Recommendations: Subgroup 1: Fostering Markets for Non-digester Projects, Senate Bill 1383 Dairy and Livestock Working Group* 3 (Oct. 12, 2018), https://ww2.arb.ca.gov/sites/default/files/2020-11/dsg1_final_recommendations_11-26-18.pdf.
[82] A reduction of waste is the preferred management method in the Environmental Protection Agency's waste management hierarchy for decision-making. *Waste Management Hierarchy and Homeland Security Incidents,* ENV'T PROT. AGENCY, https://www.epa.gov/homeland-security-waste/waste-management-hierarchy-and-homeland-security-incidents (last visited Oct. 12, 2021).
[83] Emily Grubert, *At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates*, 15 084041 ENV'T RES. LETTERS Aug. 2020, 2.

reduce emissions, it should be the baseline to which any emissions reductions associated with anaerobic digestion are compared.

Moreover, because factory farm gas can be sold as a fuel and used to generate significant supplemental revenue from LCFS credits, over time "it is not only possible but expected…to increase methane production beyond what would have happened anyway."[84] Any manure production that has been incentivized by LCFS credit revenue will also result in intentionally created methane, which according to one recent study, *is always GHG-positive*.[85]

Finally, the Agro-Ecological Zone Emissions Factor (AEZ-EF) used to measure emissions from land-use change by CA-GREET3.0, and therefore by Tier 2 applicants, fails to account for the full impacts from the industrial dairy and pig facilities producing factory farm gas.[86] CARB's Executive Officer may require fuel producers to include six specific "feedstock/finished biofuel combinations," in their calculations.[87] These feedstocks include corn, sugarcane, sorghum grain ethanol, soy, canola, and palm biomass-based diesel.[88] Apart from land-use change related to livestock grazing (which is rarely relevant to industrial livestock operations), the AEZ-EF model does not address the land-use change associated with industrial dairy farming which are required for the production of factory farm gas.[89]

The overly narrow life cycle analysis in the factory farm gas pathways not only undermines the program's capacity to incentivize reductions, but violates AB 32's mandate that "[T]he state board shall rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by this section."[90] Scientific literature provides a more complete account of greenhouse gases emitted during the life cycle of factory farm gas produced from dairy and pig facilities. These analyses incorporate emissions from feed production, enteric fermentation, farm management and operations, and the treatment, use, or disposal of digestate residues produced during anaerobic digestion in addition to manure management emissions.[91] Omitting these essential stages from the LCFS factory farm gas pathways neglects a significant portion of emissions involved in producing

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[84] *Id.* at 5.
[85] *Id*. at 4.
[86] CAL. CODE REGS. TIT. 17 § 95488.3.
[87] CAL. CODE REGS. TIT. 17 § 95488.3(d).
[88] *Id*.
[89] Richard J. Pelvin et al., *Agro-ecological Zone Emission Factor (AEZ-F Model): A model of greenhouse gas emissions from land-use change for use with AEZ-based economic models* 3, 31 (Feb. 21, 2014), https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/lcfs_meetings/aezef-report.pdf.
[90] CAL. HEALTH & SAFETY CODE § 38562 (e). In Resolution 19-27, CARB itself stated that the LCFS "was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective reductions in GHG emissions from transportation fuel used in California." CAL. AIR RES. BD., RES. 19-27, *supra* note 55.
[91] *See, e.g.,* E. M. Esteves et al., *Life cycle assessment of manure biogas production: A review,* 218 J. CLEAN PROD. 411–423 (2019), https://doi.org/10.1016/j.jclepro.2019.02.091; E. Cherubini et al., *Life cycle assessment of swine production in Brazil: a comparison of four manure management systems*, 87 J. CLEAN PROD. 68–77 (2015), https://doi.org/10.1016/j.jclepro.2014.10.035; V. Paolini et al., *Environmental impact of biogas: A short review of current knowledge*, 53, J. ENV'T SCI. HEALTH A 899–906 (2018), https://doi.org/10.1080/10934529.2018.1459076.

manure and, as a result, the pathway treats manure as if it is produced from thin air or as if lagoons of liquid manure occur naturally in the San Joaquin Valley. [92]

The LCFS regulation mandates a full accounting of the aggregate life cycle emissions from a given fuel. In CARB Resolution 19-27, the agency reiterated that the "[d]etermination of a fuel's energy demand and carbon intensity value is based on a "well-to-wheel" analysis, which includes production and processing, distribution, and vehicle operation.[93] And yet the factory farm gas pathways leave glaring gaps in the life cycle analysis beyond the narrow system boundaries. The premise that manure originates in manure lagoons ready for capture with no attendant emissions defies logic, yet CARB has embraced this to create an absurdly low carbon intensity value and inflated credit generating industry.

2. The fuel pathways for biomethane from dairy and swine manure fail to ensure that credited emissions reductions are additional to reductions that would have otherwise occurred.

The LCFS prohibits awarding credits for emissions reductions that are already required by law.[94] As a market-based compliance mechanism, however, the LCFS must also prohibit the award of credits for "any other greenhouse gas emission reduction that otherwise would occur."[95] While CARB promulgated the LCFS as an early action measure, CARB designed and implemented the LCFS as a market-based compliance mechanism. CARB itself described the LCFS as a market-based mechanism when promulgating amendments to the LCFS:

> The LCFS is a market-based approach designed to reduce the carbon intensity of transportation fuels by 10 percent by 2020, from a 2010 baseline. It is important to note that the Cap-and-Trade Program and the LCFS program have complementary, but not identical programmatic goals: Cap-and-Trade is designed to reduce greenhouse gasses from multiple sources by setting a firm limit on GHGs; the LCFS is designed to reduce the carbon intensity of transportation fuels. As a market-based, fuel-neutral program, the LCFS provides regulated parties with flexibility to achieve the most cost-effective approach for reducing transportation fuels' carbon intensity. . . .

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[92] A Naranjo et al., *Greenhouse Gas, Water, and Land Footprint Per Unit of Production of the California Dairy Industry Over 50 Years*, 103 J. DAIRY SCI. 3760–3773 (2020), https://www.journalofdairyscience.org/article/S0022-0302(20)30074-6/pdf; C. Alan Rotz et. al., *The Carbon Footprint of Dairy Production Systems Through Partial Life Cycle Assessment*, 93 J. DAIRY SCI. 1266–1282 (2010), https://doi.org/10.3168/jds.2009-2162; C. Alan Rotz, *Modeling Greenhouse Gas Emissions from Dairy Farms*, 101 J. DAIRY SCI. 6675–6690 (2018) https://www.sciencedirect.com/science/article/pii/S002203021731069X.

[93] CAL. AIR RES. BD., RES. 19-27, *supra* note 55; *see also* CAL. AIR RES. BD., *Appendix D: Draft Environmental Analysis* (Jan. 2, 2015), https://ww2.arb.ca.gov/sites/default/files/classic/regact/2015/lcfs2015/lcfs15appd.pdf.

[94] *See* CAL. CODE REGS. TIT. 17 § 95488.9(f)(1)(B) ("A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that… the baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.")

[95] CAL. HEALTH & SAFETY CODE § 38562(d)(2).

> ARB staff disagrees that the LCFS is fundamentally a command-and-control system. The LCFS is a fuel-neutral, market-based program that does not give preference to specific transportation fuels and instead bases compliance on a system of credits and deficits based on each fuel's carbon intensity. Carbon intensity (CI) is a measure of the GHG emissions associated with the various production, distribution, and consumption steps in the "life cycle" of a transportation fuel. It is difficult to respond with depth to this assertion because the commenter provides no specifics to support the claim that the LCFS is not market-based. Notably, the commenter does not describe what components of the program could be considered command-and-control.[96]

Additionally, CARB's descriptions of the LCFS program closely parallel the statute's definition of "market-based compliance mechanism." The defintion states in relevant part that a market-based compliance mechanism is: "A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases."[97] CARB explains that the LCFS has a "market for credit transactions," where "entities with credits to sell can opt to pledge credits into the market and entities needing credits must purchase their pro-rata share of these pledged credits."[98] CARB explains that credits are generated relative "to a declining CI benchmark for each year."[99] The LCFS exhibits many if not most of the features of a market-based compliance mechanism, including a Cap-and-Trade allowance-like system with yearly declinations,[100] transaction rules,[101] recordkeeping and auditing requirements,[102] an account system to manage credit transfers – the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS),[103] and a portal that applicants must use to demonstrate compliance,[104] among others. In addition to CARB's interpretation, designation, and treatment of the program as a market-based

[96] CAL. AIR RES. BD., *Final Statement of Reasons for Rulemaking, Including Summary of Comments and Agency Response* 679-681 (2015), *available at* https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/fsorlcfs.pdf. *See also* CAL. AIR RES. BD., *Responses to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations* at B4-42 (2018), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/rtcea.pdf (CARB responding, "Because the LCFS is a market-based mechanism…"); CAL. AIR RES. BD., *Staff Discussion paper: Renewable Natural Gas from Dairy and Livestock Manure 6* (April 13, 2017), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/041717discussionpaper_livestock.pdf (in which CARB staff note in 2017 discussion paper that additionality requirements for the LCFS *are* intended to be identical to those of the compliance offset protocol, "ensure any crediting is for GHG reductions resulting from actions not required by law or beyond business as usual").

[97] CAL. HEALTH & SAFETY CODE § 38505(k). Note that this is one of two definitions provided.

[98] CAL. AIR RES. BD., *LCFS Basics* (2019), *available at* https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited Oct. 12, 2021).

[99] *Low Carbon Fuel Standard: About*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about (last visited Oct. 12, 2021).

[100] *See* CAL. CODE REGS. TIT. 17 §§ 95482 – 95486.

[101] *See* CAL. CODE REGS. TIT. 17 § 95491.

[102] *See* CAL. CODE REGS. TIT. 17 § 95491.1.

[103] CAL. CODE REGS. TIT. 17 § 95483.2(b). ("The LRT-CBTS is designed to support fuel transaction reporting, compliance demonstration, credit generation, banking, and transfers.").

[104] *See* CAL. AIR RES. BOARD, *Low Carbon Fuel Standard – Annual Reporting and Verification User Guide* 3-4 (Aug. 9, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/Reporting_and_Verification_User_Guide.pdf.

mechanism and the overall structure of the regulation evincing the same, the designation of California's LCFS as a market-based mechanism is ubiquitous in academic and technical literature.[105]

Because the LCFS is a market-based compliance mechanism, section 38562(d)(2) of the Health & Safety Code requires that CARB ensure greenhouse gas emissions reductions in the LCFS are "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur."[106] Additionality requirements are essential for market-based programs that operate with a declining emissions benchmark, like the LCFS. Because regulated parties are permitted to emit above the benchmark so long as they offset these emissions with the purchase of credits, the LCFS must ensure that credits reflect reductions that are additional to claim a net reduction. The additionality requirement enumerated in the LCFS currently is far too narrow. It requires only that reductions are "additional to any legal requirement for the capture and destruction of biomethane."[107] This weak language incorporates only one of the two prongs required by AB 32 and does not ensure that reductions are additional to those from other LCFS incentives. CARB should grant this petition and amend the LCFS to include the broader additionality requirement.

As implemented to date, the LCFS program allows generation, sale, and use of factory farm gas credits that are plainly not additional when the methane reductions attributed to these LCFS credits result from, and are attibuted to, other programs and revenue sources. The LCFS 1) allows the same emissions reductions to be counted and credited by multiple emission reductions programs; and 2) awards credits to facilities receiving public funding for anaerobic digesters and related infrastructure, even when that funding is contingent on the construction of this equipment.

Numerous state and federal funding opportunities, incentives, and other subsidies are available for anaerobic digestors at factory farms. The Aliso Canyon Mitigation Agreement that CARB negotiated with Southern California Gas Company (SoCalGas) legally requires SoCalGas to pay for methane reductions at factory farm dairies in California.[108] The parties intended the agreement to mitigate the harms from the most damaging man-made greenhouse gas leak in United States history – SoCalGas' ruptured well that released at least 109,000 metric tons of methane before it was sealed.[109] SoCalGas funds the construction of digesters, which are intended to mitigate the leaked methane, and receives "mitigation credits" for the associated emissions reductions. The conditions of the agreement legally require changes intended to reduce emissions

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105 *See, e.g.,* CENTER FOR CLIMATE AND ENERGY SOLUTIONS, *Policy Considerations for Emerging Carbon Programs* 2 (June 2016), https://www.c2es.org/wp-content/uploads/2016/06/emerging-carbon-programs.pdf (describing Low Carbon Fuel Standards as an example of a market-based policy option, specifically of a baseline-and-credit program); *Regional Activities*, NATIONAL LOW CARBON FUEL STANDARD PROJECT, https://nationallcfsproject.ucdavis.edu/regional-activities/ (stating California's "LCFS is a market-based mechanism") (last visited Oct. 12, 2021).

106 CAL. HEALTH & SAFETY CODE § 38562(d)(2).

107 CAL. CODE REGS. TIT. 17 § 95488.9(f)(1).

108 *People v. Southern California Gas Company,* Case Nos. BC602973 & BC628120, Appendix A to Consent Decree, Mitigation Agreement, *available at* https://www.arb.ca.gov/html/aliso-canyon/aliso-canyon-mitigation-agreement.pdf?_ga=2.146452402.708596706.1633463951-1172357510.1559256345.

109 CAL. AIR RES. BD., *Responses to Frequently Asked Questions: Aliso Canyon Litigation Mitigation Settlement*, https://ww3.arb.ca.gov/html/aliso-canyon/aliso-canyon-faqs.pdf?_ga=2.67705041.1139070712.1533833674-1489205872.1532954259.

and yet at least eight facilities that receive this funding have also applied for LCFS credits for biomethane production. California Bioenergy sought LCFS credits for the S&S, Moonlight, Hamstra, Trilogy, Maple, T&W, BV Dairy, and Western Sky dairies.[110] These eight dairies are among seventeen that participate in the Aliso Canyon Mitigation Agreement.[111] Under no circumstances should mitigation for the Aliso Canyon disaster simultaneously qualify for credits generated and used in the LCFS.

Furthermore, the Legislature has appropriated public funds from the Greenhouse Gas Reduction Fund (GGRF) for several years to secure climate benefits. The California DDRDP, funded through the GGRF, provides funding for factory farm gas infrastructure. The California Department of Food and Agriculture describes the DDRDP as "financial assistance for the installation of dairy digesters in California, which will result in reduced greenhouse gas emissions."[112] Since 2015, the DDRDP has funded 117 dairy projects through the DDRDP, for a total of $195,025,884, and for which the CDFA claims 21,023,793 MTCO2e of methane reductions.[113] CARB also claims these reductions in a report to the Legislature on the climate benefits from these grants.[114] At least eight of these dairy projects, and likely many more, have received DDRDP grants and sought LCFS credits. For instance, California Bioenergy sought LCFS credits for the S&S, Moonlight, Hamstra, Trilogy, Maple, T&W, BV Dairy, and Western Sky dairies, all of which received DDRDP grants.[115] Importantly, the DDRDP purports to limit how grant monies may be used, but it does not prohibit a project from generating LCFS credits.[116]

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[110] *See* CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0185, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_cover.pdf; CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

[111] CAL. AIR RES. BD., *Aliso Canyon Natural Gas Leak, List of dairies involved in the mitigation agreement*, https://www.arb.ca.gov/html/aliso-canyon/aliso-canyon-mitigation-project-dairy-sites.pdf?_ga=2.216890962.535652136.1632321175-1949797088.1632171356.

[112] *Dairy Digester Research & Development Program*, CAL. DEPT. OF FOOD & AG., https://www.cdfa.ca.gov/oefi/ddrdp/ (last visited Oct. 19, 2021).

[113] CAL. DEPT. OF FOOD & AG., *CDFA Dairy Digester Research and Development Program Flyer (Sept. 2021)*, *available at* https://www.cdfa.ca.gov/oefi/ddrdp/docs/DDRDP_flyer_2021.pdf. (A list of all project recipients can be found at CAL. DEPT. OF FOOD & AG., *Dairy Digester Research and Development Program Project-Level Data (Sept. 17, 2021),* https://www.cdfa.ca.gov/oefi/DDRDP/docs/DDRDP_Project_Level_Data.pdf.)

[114] CAL. CLIMATE INVESTMENTS, *2021 California Climate Investments Annual Report*, Table 2 (2021), *available at* http://ww2.arb.ca.gov/sites/default/files/cap-and-trade/auctionproceeds/2021_cci_annual_report.pdf.

[115] *See* CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0185 *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0185_cover.pdf; CAL. AIR RES. BD., Low Carbon Fuel Standard Tier 2 Pathway Application B0198, *available at* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_cover.pdf.

[116] *See 2020 DDRDP Request for Grant Applications,* CAL. DEPT. OF FOOD & AG., https://www.cdfa.ca.gov/oefi/DDRDP/docs/2020_DDRDP_RGA_Public_Comments.pdf (last visited Oct. 5, 2021) ("Once a project has been awarded funds, the project may not: • Change or alter their biogas end-use during the project term. • Change the herd size beyond the limits established by the existing dairy operation's permits during the project term. • Change ownership of the dairy and/or partnership entities… • Duplicate equipment or activities that will receive funding from the California Public Utilities Commission (CPUC) pilot project authorized by California Health and Safety Code Section 39730.7(d)(2) (e.g., interconnection costs). *Note: Biogas conditioning and clean-up costs are allowable under the DDRDP.* • Commercial dairy operations that have already accepted, or plan to accept a grant award by CDFA's Alternative Manure Management Program (AMMP).") (emphasis added). Note that by allowing DDRDP funds to cover upgrade costs and other costs that the CPUC incentives program cannot, the CDFA has ensured that factory farm gas projects can benefit from multiple funding sources.

Other public funds authorized by the Legislature subsidize factory farm gas projects seeking to interconnect with utility natural gas pipelines.[117] This additional source of funds quickly became oversubscribed, prompting the California Public Utilities Commission to double the size of the program, all paid for with proceeds from sales of Cap-and-Trade allowances.[118] The California Public Utilities Commission went a step further, proposing in 2017 that participants in the SB1383 dairy biomethane Pilot Program could avoid the costs associated with gas production equipment, specifically gathering lines and "treatment equipment."[119] In what would be a major break with California energy precedent, ratepayers got to foot the bill.[120]

Projects receiving public funds should not, under the principles of additionality, also generate LCFS credits that allow emissions elsewhere; in this situation public funds essentially allow a transportation fuel deficit holder to emit more greenhouse gases and allow the factory farm gas project to generate a financial windfall. Under no circumstances did the Legislature intend for this perverse result to occur.

This is not a hypothetical concern: CARB recently proposed approval of Tier 2 Pathway applications B0185 and B0198 for eight dairy digester projects that have received both Dairy

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[117] *See* CAL. PUB. UTILITIES COMM'N, Decision Adopting the Standard Renewable Gas Interconnection and Operating Agreement, R.13-02-008 COM/CR6/jnf at 12 (Dec. 17, 2020), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M356/K244/356244030.PDF ("D.15-06-029 created a $40 million monetary incentive program "to encourage potential biomethane producers to build and operate biomethane projects within California that interconnect with the utilities" in accordance with AB 1900 (Gatto, 2012). This monetary incentive program was subsequently codified by AB 2313 (Williams, 2016)…The $40 million approved by the CPUC for the monetary incentive program is currently fully subscribed and there is a wait list for an additional $38.5 million worth of project funding.").

[118] *See Id.* at 14 ("After weighing the benefit of increased biomethane capture and use against the modest reduction in the California Climate Credit necessary to fully fund all existing biomethane projects, including those on the waitlist, we find it appropriate to provide an additional $40 million in funding from Cap-and-Trade allowance proceeds for the monetary incentive program to fund the biomethane projects that are currently on the wait list, bringing total funding to $80 million.").

[119] Decision establishing the implementation and selection framework to implement the dairy biomethane pilots required by Senate Bill 1383 at 7-8 (Dec. 18, 2017), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352373.PDF (". . . [T]he biomethane producers should own and operate the digesters and the biogas collection lines and treatment equipment to remove hydrogen sulfide and water from the raw biogas. Although we do not allow utilities to own these facilities, the costs associated with the biogas collection lines and treatment equipment will be recovered from the transmission rates of utility ratepayers through a reimbursement to the dairy biomethane producer. Natural gas utilities will own and operate all facilities downstream of the biogas conditioning and upgrading facilities, including pipeline laterals from such facilities, to the point of receipt and any pipeline extensions.").

[120] *Id.* ("Historically the costs of gathering, gas conversion to pipeline quality specifications, transportation from a gas production site to a conversion facility, transportation from the conversion facility to the pipeline, and pipeline interconnection costs have been borne by California natural gas producers as part of the commodity cost of gas since the late 1980s, as 'gathering costs' that the CPUC has ruled should be assigned to gas producers . . . . For the purposes of the Dairy Pilots, and consistent with the language of SB 1383, we are allowing cost recovery of the biogas collection lines owned by dairy biomethane producers, and allowing utilities to own and operate pipelines that carry biomethane from biogas conditioning and upgrading facilities to existing utility transmission systems and the interconnection facilities, without changing the requirements of D.89-12-016 for non-renewable natural gas producers . . . .").

Digester Research Development Program (DDRDP) and Aliso Canyon settlement funds.[121] Both programs claim credit for the methane reductions associated with the digester projects. If the LCFS system grants credits for these same reductions and allows a deficit holder to use those credits to demonstrate compliance with the LCFS, the reductions will be without question not additional. This absurd result allows excessive emissions and CARB must grant this petition to ensure LCFS program integrity.[122]

A wide range of other state and federal financial assistance is available to factory farms to support the construction and implementation of factory farm gas systems. This public financing comes in the form of grants, "production incentive payments, low-interest financing, tax exemptions and incentives, and permitting assistance."[123] The California Energy Commission provides funding for factory farm gas development through its Natural Gas Research and Development program.[124] The program provides $100 million annually to various fuel transportation projects, including factory farm gas.[125] The Environmental Quality Incentives Program (EQIP) is a federal program that provides matching funds for agricultural operations to contract with Natural Resources Conservation Service to develop technology or infrastructure with environmental benefits, including the construction of anaerobic digestion infrastructure.[126] The Rural Energy for America Program also provides federal funds to develop factory farm gas systems. *See* 7 U.S.C. § 8107.

The LCFS is demonstrably and avowedly a market-based compliance mechanism and is thus properly subject to the requirements of section 38562(d)(2). As the forgoing demonstrates,

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[121] These dairy digester projects also may participate in the California Public Utilities Commission pilot projects, as California Bioenergy projects, which would confer additional public funds. *See* CAL. PUB. UTILITIES COMM'N, Press Release: CPUC, CARB, and Department of Food and Agriculture Select Dairy Biomethane Proejcts to Demonstrate Connection to Gas Pipelines (December 3, 2018), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M246/K748/246748640.PDF.

[122] This has caused confusion in Tier 2 application comments. For example, in comments on several applications, the Chair of the Board for the Kings County Board of Supervisors commented to ask how these applicants could participate in the LCFS without double counting reductions, given that they also participated in bioMAT. CARB did not respond to the comments. *See* CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 61 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0106_verboon_comments.pdf (commenting on Tier 2 Application B0106); CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 60 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0105_verboon_comments.pdf (commenting on Tier 2 Application B0105); CAL. AIR RES. BD., Comment Log Display, Doug Verboon, Comment 59 for Public Comments for LCFS Pathway Applications (tier2lcfspathways-ws) - 2nd Workshop (Nov. 25, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b104_verboon_comments.pdf (commenting on Tier 2 Application B0104).

[123] CAL. DAIRY CAMPAIGN, *Economic Feasibility of Dairy Digester Clusters in California: A Case Study* 45, (June 2013) https://archive.epa.gov/region9/organics/web/pdf/cba-session2-econ-feas-dairy-digester-clusters.pdf.

[124] *Natural Gas Research and Development Program*, CAL. ENERGY. COMM'N., https://www.energy.ca.gov/sites/default/files/2019-05/naturalgas_faq.pdf (last visited Oct. 18, 2021).

[125] *Clean Transportation Program*, CAL. ENERGY. COMM'N., https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program (last visited Oct. 18, 2021).

[126] Environmental Quality Incentives Program, NAT'L RES. CONS. SERVICE, https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/programs/financial/eqip/.

private and public funding either have been or could be used to reduce methane emissions from pig and dairy facilities.[127] The LCFS should not allow fuel producers to generate credits from such non-additional reductions that deficit holders then use to justify their excess emissions, undermining the integrity of the LCFS program.

3. CARB's crediting of non-additional reductions and the inflated credit value from CARB's failure to account for the full quantity of life-cycle emissions both incentivize increased manure generation and manure liquification and constitute a failure to achieve the maximum technologically feasible and cost-effective greenhouse gas emissions.

Including inflated credits and credits for non-additional reductions contravenes the fundamental purpose of the LCFS: to reduce greenhouse gas emissions associated with transportation fuels. Inflated credits and credits for non-additional reductions have the effect of increasing manure generation and liquification, and its associated greenhouse gas emissions. Additionally, by purchasing inflated credits, deficit generators can more easily meet their compliance obligations without reducing their emissions. As a result of these deficiencies, the LCFS fails to achieve the maximum technologically feasible and cost-effective emissions reductions.

The factory farm gas industry is currently made profitable by the LCFS and similar programs. In fact, "[w]ell over 50% of the revenue from most projects generating credits comes from the [LCFS and Federal RIN] credits."[128] A recent report by a private investment firm on the promising growth prospects for factory farm gas concluded that "operators are not in the business of producing RNG, they are in the business of monetizing RNG's environmental attributes through various federal and state programs."[129] This is by design: the goal of the LCFS factory farm gas pathways is to incentivize the development of factory farm gas as an alternative fuel. This goal assumes incentivizing development of factory farm gas will result in a net decrease in manure methane emissions. But this assumption – the result of the deficient life cycle analysis and inclusion of non-additional reductions – is mistaken.

Increased profitability and growth of the factory farm gas industry does not necessarily entail a reduction in manure methane emissions from participating factory farms. Due to the poor design of the LCFS pathways for factory farm gas, the program encourages not only capture of manure methane, as intended, but increased production of that methane. Revenue from LCFS credits is an increasingly enticing source of potential profit for many factory farms. In the case of

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[127] For this reason, LCFS credits also should not be issued to facilities that already operate digesters to produce low-CI electricity but seek to convert to producing biomethane, as no truly additional emissions reductions occur upon switching fuel production pathways.

[128] Annie AcMoody & Paul Sousa, *Western United Dairies, Interest in California Dairy Manure Methane Digesters Follows the Money*, CoBANK, at 4, (Aug. 2020), https://www.cobank.com/documents/7714906/7715329/Interest-in-California-Dairy-Manure-Methane-Digesters-Follows-the-Money-Aug2020.pdf/be11d7d6-80df-7a7e-0cbd-9f4ebe730b25?t=1603745079998.

[129] STIFEL EQUITY RESEARCH, *Energy & Power – Biofuels: Renewable Natural Gas, A Game-Change in the Race for Net-Zero* (March 8, 2021), *available at* https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/60ad5a8802a04b71ca252414/1621973643907/Stifel+RNG+Analysis.pdf.

industrial dairy operations, these inflated credits provide certainty for operators seeking to maintain or expand herd sizes by providing significant additional income to supplement volatile milk revenue.[130] In 2017, CARB itself "assume[d] that California's LCFS credits [would] contribute revenue of $865,000" (assuming $100 per metric ton of CO_2).[131] The average LCFS credit price has increased significantly since this estimate was made, with 2020 prices hovering around $200 per metric ton of CO_2 (see Figure 5 in Appendix C). As a result, LCFS credits can be a more reliable income stream than milk. The LCFS not only encourages the development of factory farm gas systems but entrenches the underlying factory farms and even incentives expansion of these operations – the very sources of manure methane the factory farm gas credits are intended to reduce.

LCFS credits derive their value from recipients' ability to sell these credits to LCFS participants that generate deficits. Deficit-generating facilities include producers of conventional, high carbon intensity fuels such as gasoline and diesel fuels. This means that the life cycle analysis deficiencies and granting of credits for non-additional reductions not only incentivize increased emissions from factory farms, but also function to allow emissions in other transportation fuel industries.

Additionally, because economies of scale for anaerobic digesters favor larger herd sizes, factory farm gas producers have an incentive to produce more liquid manure, by either increasing herd size or participating in a digester cluster. This is the case for factory farm gas from both cows and pigs. In California, where most digesters use manure from lagoons to produce gas for pipeline transport, the technology requires a minimum of 2,000 cows to be economically feasible.[132] Scale is central to making the technology investment profitable, and "each additional 1,000 cows reduce the cost per cow of digester projects by 15-20%."[133] EPA AgSTAR admits that most methane digesters "are not economically viable until greater than 10,000 hogs are incorporated."[134]

The programmatic distortions described in parts III(A)(1) and (2) will drive the expansion of factory farms to supply factory farm gas, intentionally creating greenhouse gas emissions and localized pollution. CARB should rescind the factory farm gas pathways and preclude factory farm

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[130] The milk price that dairy farmers receive has fluctuated considerably over the past two decades while costs have remained relatively constant. In 2015 and 2016, dairies experienced negative average residuals (see Table 2 in Appendix C). In 2017, annual milk revenue from "a farm with 2,000 cows producing 230 hundredweight per cow per year (the average in the San Joaquin Valley)" totaled nearly $7.6 million based on the milk price of $16.50 per hundredweight. After factoring in 2017 cost estimates by the California Department of Food and Agriculture (CDFA), the "net revenue at the typical dairy in the southern San Joaquin Valley amounted to zero." *See* Justin Ellerby, CAL. CENTER FOR COOP. DEV., *Challenges and Opportunities for California's Dairy Economy* 5 (2010); William Matthews and Daniel Sumner, *Contributions of the California Dairy Industry to the California Economy in 2018*, UNIV. OF CAL. AGRIC. ISSUES CENTER 17-18 (2019), https://aic.ucdavis.edu/wp-content/uploads/2019/07/CMAB-Economic-Impact-Report_final.pdf; Hyunok Lee. & Daniel A. Sumner, *Dependence on policy revenue poses risks for investments in dairy digester,* 72 CAL. AG. 226-235, 231 (2018), https://doi.org/10.3733/ca.2018a0037.

[131] Hyunok Lee & Daniel A. Sumner, *supra* note 130 at 232.

[132] GLOBAL DATA POINT, *California Incentives Spur Dairy Manure Methane Digester Developments*, GALE: BUSINESS INSIGHTS (Doc. No. A631672444) (Aug. 6, 2020).

[133] *Id.*

[134] ENV'T PROT. AGENCY, *AgSTAR, Project Development Handbook: A Handbook for Developing Anaerobic Digestion/Biogas Systems on Farms in the United States* 7-2, n. 58, https://www.epa.gov/sites/default/files/2014-12/documents/agstar-handbook.pdf (3rd Ed.).

gas from the LCFS program. In the alternative, CARB must amend the regulation to ensure that the carbon intensity values account for the full life cycle of dairy and pig facility emissions, including production and pre-processing of manure feedstock and downstream emissions associated with digestate land application and composting, and prohibit credits from non-additional reductions.

B. The fuel pathways for biomethane from dairy and swine manure fail to maximize additional environmental benefits and interfere with efforts to improve air quality.

The California Legislature directed CARB to design regulations in a manner that considers overall societal benefits, including other benefits to the environment and public health, and ensure that activities taken pursuant to the regulations do not interfere with the state's efforts to improve air quality.[135] The Legislature also declared, in enacting AB 32, that it intended that CARB design reduction measures in a manner that "maximizes additional environmental and economic cobenefits for California, and complements the state's efforts to improve air quality."[136] But so long as the LCFS program includes factory farm gas and incentivizes factory farm expansions and the resulting air pollution, it cannot maximize environmental benefits or improve air quality. Moreover, given these impacts, CARB has not adequately considered overall societal costs in the regulation's design.

Monetizing a waste stream, like manure, does not eliminate that waste. The material impacts of manure (and later digestate) remain, whether or not it generates revenue for confined animal feeding operations. Nearby communities must still contend with the harms from the production, transportation, storage, and processing of this waste. If anything, monetizing a waste stream like manure exacerbates these harms by disincentivizing waste reduction. Incentivizing larger herd sizes and the liquification of more manure exacerbates existing pollution to air, water, and land, and the associated public health harms from industrial dairy and pig facilities, in addition to increased greenhouse gas emissions.[137] Additionally, factory farm gas technology creates new and additional environmental and public health harms, including through the storage, composting, and land application of digestate.

The 3.9 million residents of the San Joaquin Valley face increased health risks from breathing polluted air.[138] Industrial dairy operations emit the ammonia that contributes to the some

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[135] CAL. HEALTH & SAFETY CODE § 38562(b)(4) ("Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."); CAL. HEALTH & SAFETY CODE § 38562(b*)(*6) ("Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."). *See also* CAL. HEALTH & SAFETY CODE § 38562.5 (making section 38562(b) applicable to regulations adopted to achieve reductions beyond the statewide greenhouse gas emissions limit).

[136] CAL. HEALTH & SAFETY CODE § 38501.

[137] *EPA Activities for Cleaner Air - San Joaquin Valley,* U.S. ENV'T PROT. AGENCY, https://www.epa.gov/sanjoaquinvalley/epa-activities-cleaner-air (last updated Mar. 6, 2019).

[138] Rory Carroll, *Life in San Joaquin valley, the place with the worst air pollution in America*, THE GUARDIAN (May 13, 2016), https://www.theguardian.com/us-news/2016/may/13/california-san-joaquin-valley-porterville-pollution-poverty.

of the worst long-term and short-term $PM_{2.5}$ pollution in the United States, which causes health problems such as asthma and has been linked to premature death as described *supra* in part II.[139] Industrial dairies are also the largest source of volatile organic compounds (VOCs), which contribute to the Valley's ozone (smog) air pollution crisis.[140] The digestate from factory farm gas production can emit even more hazardous VOCs during storage. An analysis of digestate from pig manure identified nearly 50 VOCs, 22 of which are labeled hazardous by the EPA.[141] Of these 22 hazardous VOCs, "8 were identified to be or likely to be carcinogenic, and 14 were identified to be harmful to other human organs or systems."[142]

Biogenic and anthropogenic emissions of VOCs and nitrogen oxides (NOx) both form ground-level ozone, the concentration of which is "directly affected by temperature, solar radiation, wind speed and other meteorological factors."[143] VOCs from corn silage at dairies alone would be the largest source in the Valley, with such emissions forming more ozone than the VOCs emitted by passenger vehicles.[144] Breathing in ground-level ozone can trigger a variety of dangerous health problems like throat irritation, chest pain, and congestion. It can also lead to severe lung damage, making infants and the elderly more vulnerable to health effects.[145] Ozone causes respiratory inflammation, increased hospital admissions for respiratory illness, decreased lung function, enhanced respiratory symptoms for people with asthma, increased school absenteeism, and premature mortality.[146] Evidence indicates that "adverse public health effects occur following exposure to elevated levels of ozone, particularly in children and adults with lung disease."[147] The San Joaquin Valley is classified as an extreme ozone nonattainment area for the 1997 and 2008 8-hour ozone standards.[148]

Industrial dairies are also the largest source of ammonia.[149] Factory farm gas production adds even more ammonia to San Joaquin Valley air: ammonia emissions from digestate increased 81% relative to raw manure.[150] Anaerobic digestion causes this increase in ammonia emissions, "due to an increased concentration of ammoniacal nitrogen."[151] In addition to its unpleasant odor,

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[139] *Id.*
[140] *See* SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DIST., *2016 Plan for the 2008 8-Hour Ozone Standard, Appendix B*, *available at* http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/b.pdf.
[141] Yu Zhang et al., *Characterization of Volatile Organic Compound (VOC) Emissions from Swine Manure Biogas Digestate Storage*, 10 ATMOSPHERE 1, 7 (2019), https://doi.org/10.3390/atmos10070411.
[142] *Id.* at 8.
[143] 73 FED. REG. 16436, 16437 (March 27, 2008).
[144] *See* Cody J. Howard, et al., *Reactive Organic Gas Emissions from Livestock Feed Contribute Significantly to Ozone production in Central California*, 44 ENV'T SCI. TECHNOL. 7 2309–2314 (2010), https://pubs.acs.org/doi/abs/10.1021/es902864u.
[145] *Id.*
[146] 73 Fed. Reg. 16436, 16440 (March 27, 2008).
[147] 83 FED. REG. 61346, 61347 (November 29, 2018).
[148] 75 FED. REG. 24409 (May 5, 2010); 77 FED. REG. 30088, 30092 (May 21, 2012).
[149] SAN JOAQUIN VALLEY AIR CONTROL DIST., 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, Appendix B and Appendix G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf and http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
150 *See* Holly, et al., *Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land disposal*, AG., ECOSYSTEMS AND ENV'T 239 (2017) 410–419, https://www.researchgate.net/publication/313731233_Greenhouse_gas_and_ammonia_emissions_from_digested_and_separated_dairy_manure_during_storage_and_after_land_application.
[151] *Id.*

which degrades quality of life for nearby residents, ammonia "is corrosive and can be a powerful irritant to skin, eyes, and digestive and respiratory tissues."[152] Ammonia also reacts with oxides of nitrogen to form ammonium nitrate, the most significant component of the San Joaquin Valley's $PM_{2.5}$ pollution problem.[153] Homes located within a quarter mile of a dairy confined animal feeding operation have experienced higher concentrations of both ammonia and particulate matter.[154] In addition to the harms of PM2.5 describes above, larger particles of dust pollution from factory farm dairies also carry harmful allergens and endotoxins to nearby homes.[155] Endotoxins are a "powerful inflammatory agent" that can interact with other components and lead to respiratory issues, and allergens can worsen asthma symptoms.[156] A study in rural Washington found that higher exposure to pollution from confined animal feeding operations was associated with degraded lung function in children with asthma living nearby.[157]

Depending on the physical characteristics (temperature, pH, total solid content) and the speed and frequency of the mixing process used to treat it, digestate from factory farm gas production can release dangerous concentrations of hydrogen sulfide.[158] High hydrogen sulfide emission levels are associated with a total solid content of seven percent, "which is the most appropriate for pumping and mixing of dairy manure."[159] Increasing the speed and frequency of mixing while in storage can also contribute to higher hydrogen sulfide emissions from digestate.[160] These emissions can have severe impacts on human health, particularly farm workers, and can even lead to death.[161] Furthermore, hydrogen sulfide may be detected on fields where manure is sprayed for fertilizer, and the gaseous substance can be dispersed by the wind.[162] Hydrogen sulfide gas is a respiratory tract irritant and in higher concentrations or with longer exposure, it can cause a pulmonary edema.[163] The acute symptoms of hydrogen sulfide exposure include nausea, headaches, delirium, disturbed equilibrium, tremors, convulsions, and skin and eye irritation.[164]

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[152] D'Ann L. Williams et al., *Airborne cow allergen, ammonia and particulate matter at homes vary with distance to industrial scale dairy operations: an exposure assessment*, 10 ENV'T HEALTH 1, 3 (2011), https://doi.org/10.1186/1476-069X-10-72.

[153] SAN JOAQUIN VALLEY AIR CONTROL DIST., *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards*, Appendix B and Appendix G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf and http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.

[154] D'Ann Williams et al., *Cow allergen (Bos d2) and endotoxin concentrations are higher in the settled dust of homes proximate to industrial-scale dairy operations*, 26 J. EXPOSURE SCI. ENV'T EPIDEMIOLOGY 42, 46 (2016) https://doi.org/10.1038/jes.2014.57.

[155] *Id.*

[156] *Id.* at 42.

[157] Christine Loftus et al., *Estimated time-varying exposures to air emissions from animal feeding operations and childhood asthm*a, 223 INT. J. OF HYGIENE AND ENV'T HEALTH 192 (2020) https://doi.org/10.1016/j.ijheh.2019.09.003.

[158] Fetra J. Andriamanohiarisoamanana et al., *Effects of handling parameters on hydrogen sulfide emission from stored dairy manure*, 154 J. ENV'T MGMT. 110, 112-115 (2011), https://doi.org/10.1016/j.jenvman.2015.02.003.

[159] *Id.* at 115.

[160] *Id.* at 114.

[161] *Id.* at 110.

[162] *See* Agency for Toxic Substances and Disease Registry, Toxicological Profile for Hydrogen Sulfide and Carbonyl Sulfide, DEP'T OF HEALTH AND HUMAN SERVICES 27-138 (2016), https://www.atsdr.cdc.gov/toxprofiles/tp114.pdf; *See also* Amy Schultz et al., *Residential proximity to concentrated animal feeding operations and allergic and respiratory disease*, 130 ENV'T INT. 104911, 1 (2019), https://doi.org/10.1016/j.envint.2019.104911.

[163] *See* Agency for Toxic Substances and Disease Registry, *supra* note 162 at 27-138.

[164] *Id.*

Finally, inhalation of high concentrations or long-term exposure to hydrogen sulfide can result in extremely rapid unconsciousness and eventual death.[165]

Factory farm dairies also pollute the San Joaquin Valley's groundwater, primarily through the disposal of manure by land application on crops, which causes severe public health impacts to nearby communities. The Valley contains about half of California's 300 public water systems that currently serve unsafe drinking water.[166] This number does not include private wells and water systems serving fewer than 15 households. Unsafe water systems are concentrated in small towns and unincorporated communities.[167] Common pollutants in water from factory farm runoff include nitrogen, phosphorus, heavy metals, and pharmaceuticals.[168]

Nitrate contamination of water resources is one of the most widely documented environmental impacts in California's dairy-producing regions. Most nitrate contamination comes from chemical fertilizers and animal manure applied to fields.[169] Nitrogen application often far exceeds the crops' rate of nutrient intake and the soil's ability to absorb nutrients, which then leach into groundwater.[170] A study by University of California Davis found that 96% of nitrate pollution in the region comes from nitrogen applied to cropland, a third of which is in the form of animal manure.[171] The 2019 Central Valley Dairy Representative Monitoring Program reported that nitrate concentrations exceeded the maximum contaminant level in groundwater at all of the 42 dairy facilities.[172] The program identified the application of manure to crop fields as the main source of groundwater contamination, while finding other unaccounted nitrogen sources – too many cows – at the dairy facilities contributing to the excessive nitrate contamination.[173]

Between 1999 and 2008, seven out of eight counties in the San Joaquin Valley had above-average rates of Sudden Infant Death Syndrome which can be caused by nitrate contamination. 70% of San Joaquin Valley households believed their tap water to be unsafe when surveyed in 2011, and nitrate pollution still appears to be rising.[174] A 2016 study that mapped out the mass flows of nitrogen in the San Joaquin Valley, estimated that the health costs of total nitrate leaching to groundwater caused $500 million per year in health damages.[175] Application of biogas digestate, either as a liquid or composted solids,[176] will continue the trend in nitrate contamination in the San

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165 *Id.*
166 J.A. Del Real, *They Grow the Nation's Food, but They Can't Drink the Water*, N.Y. TIMES (May 21, 2019), https://www.nytimes.com/2019/05/21/us/california-central-valley-tainted-water.html.
167 *Id.*
168 JoAnn Burkholder et al., *Impacts from Waste from Concentrated Animal Feeding Operations on Water Quality*, 115 ENV'T HEALTH PERSPECTIVES 308, 308 (2007), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC1817674/.
169 *The Sources and Solutions: Agriculture*, U.S. ENV'T PROT. AGENCY, https://www.epa.gov/nutrientpollution/sources-and-solutions-agriculture (last updated July 30, 2020).
170 *Id.*
171 Harter et al., *Addressing Nitrate in California's Drinking Water with a Focus on Tulare Lake Basin and Salinas Valley Groundwater*, CENTER FOR WATERSHED SCI., UNIV. CAL., DAVIS, 17 (2012).
172 CENTRAL VALLEY DAIRY REP. MONITORING PROG., *Summary Representative Monitoring Report* at 8 (Revised 2020).
173 *Id.*
174 *Id.* at 28.
175 Ariel I. Horowitz et al., *A multiple metrics approach to prioritizing strategies for measuring and managing reactive nitrogen in the San Joaquin Valley of California*, 11 ENV'T RES. LETTERS 1, 11 (2016).
176 Roger Nkoa, *Agricultural benefits and environmental risks of soil fertilization with anaerobic digestates: A review*, 34 AGRON. SUSTAIN. DEV. 473, 473–492 (2014).

Joaquin Valley in particular, compounding the increase from the LCFS's subsidizing increased manure production.

In addition to the emissions from digestate storage and land application, certain Tier 2 anaerobic digester facilities generate additional air pollutants using factory farm gas to power internal combustion engines that generate electricity onsite.[177] According to a 2015 study commissioned by CARB, this form of electricity generation produces criteria air pollutants, like NOx and particulate matter.[178] Furthermore, the study found this technology would increase NOx emissions by 10 percent, exacerbating air quality in the Valley, in violation of CARB's duty to ensure that its programs do not interfere with efforts to reduce air pollution.[179] The San Joaquin Valley Unified Air Pollution Control District also documents criteria pollutant emissions from electricity generation from factory farm gas.

For example, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site.[180] And this project, as permitted by the Air District with required pollution control technology, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM10, and 3.18 tons/year of VOC.[181] Compared to a natural gas combined cycle plant in Avenal permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, SOx, and VOC emissions per unit of electricity generated.[182] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase offset emission reduction credits for the toxic air pollution emitted.[183] This facility *increases* air pollution. But California Bioenergy also sought for LCFS credits under a Tier 2 pathway application for the Lakeview Dairy project.[184] By allowing polluting facilities like Lakeview Dairy to generate credits for "renewable" natural gas, despite the harmful health impacts associated with emissions from the use of factory farm gas to generate electricity, CARB ignores its statutory obligation not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[185]

Because the LCFS has resulted in and will continue to incentivize an increase in dangerous pollution to the air, water, and land of the San Joaquin Valley, it fails to comply with section

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177 Arnaud Marjollet, *District Notice of Preliminary Decision*, San Joaquin Valley: Air Pollution Control (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf; *see also* CAL. AIR RES. BD., Staff Summary, Tier 2 Pathway Application B0104, Lakeview Dairy, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
178 Marc Carreras-Sospedra et al., *Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California* at 9-10 (Feb. 2015), https://ww2.arb.ca.gov/sites/default/files/classic//research/apr/past/11-307.pdf.
179 *Id*. at 4, 13.
180 Arnaud Marjollet, *supra* note 177.
181 *Id*. at 14.
182 Brent Newell, *Comments filed to California Energy Commission*, 4 (July 11, 2017), *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=220110&DocumentContentId=29811; Arnaud Marjollet, *supra* note 177 at 20.
183 *Id*.
184 CAL. AIR RES. BD., Staff Summary, Tier 2 Pathway Application B0104, Lakeview Dairy, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
185 CAL. HEALTH & SAFETY CODE § 38562 (b).

38562(b) (4) and (6) of the Health and Safety Code. Additionally, the LCFS program violates the Legislature's intent, expressed in section 38501(h) of the Health and Safety Code, to maximize additional environmental benefits. CARB should grant this petition and exclude factory farm gas from the program to address these violations.

IV. CARB MUST EVALUATE AND AMEND THE LCFS TO REMEDY ITS DISPROPORTIONATE ADVERSE AND CUMULATIVE IMPACTS ON LOW-INCOME AND LATINA/O/E COMMUNITIES IN VIOLATION OF STATE AND FEDERAL LAW.

CA 11135 and Title VI of the Civil Rights Act impose an affirmative duty on CARB to ensure that its policies and practices do not have a discriminatory impact on the basis of race.[186] CA 12955 additionally prohibits any practice or program that has a discriminatory effect on members of protected classes with respect to housing opportunities, including with respect to the use and enjoyment of dwellings.[187] AB 32 requires CARB to ensure any activities undertaken in compliance with the statute do not disproportionately impact low-income populations, consider the social costs of greenhouse gas emissions, and design regulations in a manner that is equitable. CARB must assess and prevent the disparate impacts imposed by the LCFS to avoid further harm to communities and to comply with California and federal law.

A. LCFS credits and the subsequent trading of those credits incentivize activities that result in public health and environmental harms in disproportionately low-income and Latina/o/e communities, particularly in the San Joaquin Valley.

The LCFS harms communities that are disproportionately Latina/o/e and low-income. These harms stem from (1) the generation of revenue for factory farms in proportion to the amount of manure they produce, (2) the encouragement of anaerobic digestion resulting in additional environmental harms related to digestate, and (3) allowing credits to offset emissions and toxic air pollutants elsewhere in California. Each of these harms impact disproportionately low-income and Black, Indigenous, or People of Color communities.

In California, the award of LCFS credits for factory farm gas and the harms these credits incentivize are concentrated in the San Joaquin Valley.[188] Part III(A)(3) shows how the LCFS has the effect of exacerbating existing adverse impacts from factory farms by incentivizing increased production and liquification of manure. Part III(B) describes the extensive environmental and public health harms associated with the increase in liquified manure, as well as the new harms

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[186] CAL. GOV'T CODE § 11135; 42 U.S.C. § 2000d.

[187] CAL. GOV'T CODE § 12955.8; CAL. CODE REGS. TIT. 2 § 12161.

[188] The San Joaquin Valley hosts 89% of the state's dairy cow population, and all but one of its counties are ranked nationally for milk sales (See Table 3, Appendix C). CAL. DEP'T OF FOOD AND AGRIC., Small Dairy Climate Action Plan 1 (2018), https://www.cdfa.ca.gov/oefi/research/docs/CDFA_Summary_of_Final_Report.pdf; *See* Lori Pottinger, *California's Dairy Industry Faces Water Quality Challenges*, Public Institute of California (May 20, 2019), https://www.ppic.org/blog/californias-dairy-industry-faces-water-quality-challenges/ (all 117 DDRDP projects are in the Valley).

from digestate. Incentivizing expansion of factory farms may also negatively affect community and economic growth.[189] Part II shows that San Joaquin Valley communities impacted by these new and exacerbated harms are disproportionately Latina/o/e and disproportionately low-income. Part II also describes the preexisting cumulative harms impacting these communities: San Joaquin Valley residents experience "the worst" air pollution nationally, and high levels of drinking water and groundwater contamination, largely due to agricultural runoff.[190]

The LCFS's market-based structure shapes the distribution of adverse impacts imposed by its incentives. In addition to the harmful activities incentivized at credit-generating factory farm gas facilities, the LCFS facilitates harm by the deficit-generating facilities that purchase credits. In order to provide for the trading of credits and deficits, LCFS treats greenhouse gas emissions as fungible. This approach allows CARB to justify the greenhouse gas emissions from gasoline and diesel, for example, in excess of the program's benchmark when the producers of these fuels purchase the equivalent credits. This is viewed by CARB as a positive attribute of the LCFS program because it "lets the market decide" how to achieve the targeted emissions reductions. But treating emissions as fungible ignores the localized impacts of co-pollutants associated with the production, transport, and combustion of various transportation fuels. These harms do not disappear simply because a gasoline producer pays to justify its polluting practices. The sale of factory farm gas credits to LCFS deficit generators prolongs their ability to pollute, rather than make direct emissions reductions.

Given that LCFS deficit generators include producers of conventional fuels, such as gasoline, diesel, and compressed natural gas, there is good reason to believe that LCFS deficit generating industries may disproportionately harm low-income and Black, Indigenous, and People of Color – specifically Latina/o/e – communities. The vast majority of California oil and gas production is concentrated in the San Joaquin Valley and around Los Angeles.[191] California communities living in proximity to oil and gas extraction are known to be disproportionately low income and Latina/o/e.[192] In the San Joaquin Valley, the oil and gas industries are concentrated in Kern County, where residents are subject to the cumulative harms of petrochemical extraction in

[189] Research indicates that "concentration and industrialization of agricultural production removes more money from the community of which the farm is located than when smaller farms operate in the area." CHELSEA MACMULLAN, HUMANE SOC'Y OF THE U.S., DAIRY CAFOS IN CALIFORNIA'S SAN JOAQUIN VALLEY at 26 (2007), https://www.humanesociety.org/sites/default/files/archive/assets/pdfs/farm/macmullan_apa-2007_final.pdf. The ratio of payroll versus emissions produced by concentrated factory farm dairies ranks worse than the petroleum industry. *Id*. at 27. Additionally, factory farm dairy employees face greater health risks because of their proximity to air pollutants and bacteria. Working in the industry has been associated with respiratory diseases such as Chronic Bronchitis, Occupational Asthma, and Pharyngitis. *Id*. at 29. Lack of access to healthcare due to language barriers or undocumented status likely exacerbates these harms. *Id*.

[190] *See* Carroll, *supra* note 138; *see also* Burkholder, *supra* note 168 at 308.

[191] Judith Lewis Mernit, *The Oil Well Next Door: California's Silent Health Hazard*, YALE ENV'T 360 (March 31, 2021), https://e360.yale.edu/features/the-oil-well-next-door-californias-silent-health-hazard ("Kern County, as the southern end of the San Joaquin Valley, produces 70 percent of California' oil; the bulk of the rest comes out of Los Angeles.")

[192] *See, e.g.* Kyle Ferrar, *People and Production: Reducing Risk in California Extraction,* FRACTRACKER ALLIANCE, (Dec. 17, 2020), https://www.fractracker.org/2020/12/people-and-production/; John C. Fleming et al., *Disproportionate Impacts of Oil and Gas Extraction on Already "Disadvantaged" California Communities: How State Data Reveals Underlying Environmental Injustice*, https://www.essoar.org/doi/pdf/10.1002/essoar.10501675.1 (concluding that 77% of permits for oil and gas wells were issued in "communities with a higher-than-average percentage of residents living in poverty and/or communities with a majority non-white population").

addition to those of factory farm dairies. As noted in part II, Kern County has seen a recent increase in LCFS applications for factory farm gas pathways. Residents of Kern County already experience higher than average rates of Chronic Lower Respiratory Disease (CLRD), asthma, and respiratory system cancers.[193] The death rate from CLRD in Kern County from 2013 to 2016 was twelve times higher than the state's CLRD death rate during the same time period.[194] Exacerbation of CLRD cases is a primary reason for CLRD-related deaths.[195] In 2015 to 2016, 31.1% of children in Kern County had been diagnosed with asthma at some point in their life, compared to 15.2% of children statewide and 13.7% and 10.3% in Los Angeles County and Sacramento County, respectively.[196]

In addition to emissions from extraction and refining of these polluting fuels, LCFS credits can also be used to offset emissions from the combustion. The co-pollutants from these emissions likely impose disproportionate adverse impacts on low-income and Black, Indigenous, and People of Color communities in California. A 2014 analysis found that exposure to $PM_{2.5}$ from cars, trucks, and buses "is not equally distributed" across California.[197] More specifically, the analysis concluded that on average, "African American, Latino, and Asian Californians are exposed to more $PM_{2.5}$ pollution from cars, trucks, and buses than white Californians. These groups are exposed to $PM_{2.5}$ pollution 43, 39, and 21 percent higher, respectively, than white Californians."[198] Additionally, "[T]he lowest-income households in the state live where $PM_{2.5}$ pollution is 10 percent higher than the state average, while those with the highest incomes live where PM2.5 pollution is 13 percent below the state average."[199] Given that California's major diesel trucking corridors, Interstate 5 and State Highway 99, both run north-south directly through the San Joaquin Valley,[200] emissions from combustion of deficit-generating transportation fuels may well impose additional cumulative impacts on the same communities impacted by dairy factory farms as well as fossil fuel extraction and refining.

[193] Yongping Hao et al., *Ozone, Fine Particulate Matter, and Chronic Lower Respiratory Disease Mortality in the United States*, 192(3) AM. J. OF RESPIRATORY AND CRITICAL CARE MED. 337, 337–341, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4937454/.
[194] Nick Perez, *Despite decades of cleanup, respiratory disease deaths plague California county*, ENV'T HEALTH NEWS (Dec. 4, 2018) https://www.ehn.org/chronic-respiratory-disease-california-2621765230/pollution-persists.
[195] Elizabeth Oelsner et al., *Classifying Chronic Lower Respiratory Disease Events in Epidemiologic Cohort Studies*, 13 ANNALS OF THE AM. THORACIC SOC'Y 1057, 1057 (July 2016) https://doi.org/10.1513/AnnalsATS.201601-063OC.
[196] *Summary: Asthma*, KIDSDATA, https://www.kidsdata.org/topic/45/asthma/summary?gclid=Cj0KCQiAst2BBhDJARIsAGo2ldWxDuxZNs3gzxS4Qj3s048YVqkp4LWQ_nwYs7DSID4FDRTTdSsgq1waAgyxEALw_wcB (last visited Oct. 21, 2021).
[197] UNION OF CONCERNED SCI., *Inequitable Exposure to Air Pollution from Vehicles in California 1 (Feb. 2019)*, https://www.ucsusa.org/sites/default/files/attach/2019/02/cv-air-pollution-CA-web.pdf
[198] *Id.*
[199] *Id.* at 2.
[200] David Lighthall and John Capitman, *The Long Road to Clean Air in the San Joaquin Valley: Facing the Challenge of Public Engagement* 8 (Dec. 2007), CENTRAL VALLEY HEALTH POL'Y INST., https://chhs.fresnostate.edu/cvhpi/documents/cvhpi-air-quality-report07.pdf

B. CARB must amend the LCFS regulation to come into compliance with CA 11135, CA 12955, and Title VI of the Civil Rights Act of 1964 and to prevent further discrimination.

CARB has an affirmative duty under CA 11135 to ensure that its policies and practices do not disproportionately impact residents on the basis of race, color, national origin, or ethnic group identification.[201] CA 11135's prohibition on discrimination applies to the LCFS because it meets the criteria of a program that is "conducted, operated, or administered" by CARB, a California state agency.[202] CA 12955 prohibits activities that limit housing opportunities for members of protected classes, including activities and programs that interfere with the use and enjoyment of one's dwelling or that results in the location of toxic, polluting, and/or hazardous land uses in a manner that adversely impacts the enjoyment of residence, land ownership, tenancy, or any other land use benefit related to residential use. The state is subject to the prohibitions included in the Fair Employment and Housing Act.[203] Title VI of the Civil Rights Act of 1964 and implementing regulations prohibit disparate impact discrimination on the basis of race by recipients of federal funds.[204] As a recipient of federal funding, CARB is subject to Title VI.[205]

As described above, the LCFS exacerbates harms in some San Joaquin Valley communities twice over: once when it incentives the expansion of factory farm dairies and anaerobic digestion, and again when the resulting credits are sold to justify the pollution from conventional transportation fuel production, distribution, and combustion. Some (and likely all) of these harms are imposed on communities that are disproportionately Latina/o/e. Additionally, the LCFS has the effect of defeating one of the objectives of AB 32 on a discriminatory basis: to maximize additional environmental benefits and complement efforts to reduce air pollution.

Not only are there "equally effective alternative practices" to achieve the goal of reducing transportation emissions, there are alternative practices that are demonstrably both more effective and less discriminatory.[206] Reducing net greenhouse gas emissions from transportation fuels is an important and legitimate goal. Sadly, the LCFS factory farm gas pathways fail to accomplish it. Therefore, California's greenhouse gas emissions targets provide no credible justification for the LCFS's discriminatory impacts. Moreover, there are other, less harmful agricultural practices that CARB could encourage to reduce net emissions. Rather than monetize the source of greenhouse gas emissions and related co-pollutants, CARB could encourage the direct reduction of emissions at their source by supporting practices such as solid-liquid separation, scrape and vacuum

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[201] CAL. GOV'T CODE § 11135.
[202] *Id.*
[203] CA Legis. 352 (2021), CAL. LEGIS. SERV. CH. 352 (A.B. 948), amending CAL. GOVT CODE 12955; 2 CCR 12005(v); 2 CCR 12060.
[204] 42 U.S.C. §2000d; 40 C.F.R. §7.
[205] CARB has received funds EPA, including, for example, over $11.8 million in 2020 to administer the Diesel Emissions Reduction Act. Soledad Calvino, *U.S. EPA awards over $11.8 million for clean diesel projects in California*, U.S. ENV'T PROT. AGENCY (San Francisco), Aug. 30, 2020, News Release, https://www.epa.gov/newsreleases/us-epa- awards-over-118-million-clean-diesel-projects-california.
[206] *See, e.g., Elston v. Talladega Count.*, 997 F. 2d at 1413.

collection of manure, composting, and pasture-based practices. Similarly, there are less harmful policy tools that could be used to produce these reductions.[207]

CARB bears the duty to evaluate the potentially discriminatory impacts of its policies and practices and to prevent these harms in the first place, which it failed to do in the design of the LCFS regulation and fails to do on an ongoing basis. To bring the LCFS into compliance with its civil right obligations, CARB must cease and desist from operating the LCFS program in such a way that results in unlawful, discriminatory impacts as proscribed by CA Gov't Code Sections 11135 and 12955, et seq., and Title VI of the Civil Rights Act of 1964. To this end, CARB must a) conduct a disparity analysis to evaluate the program and b) amend the LCFS regulation to ensure that it does not continue to disproportionately harm low-income and Latina/o/e communities. A disparity analysis must include an evaluation of the distribution of impacts from incentives created by credit generation, direct emissions from deficit generators facilitated by the trading of LCFS credits, and the distribution of emissions from the combustion of these fuels.[208]

C. CARB failed to design the LCFS regulation in a manner that is equitable and fails on an ongoing basis to consider the social costs of greenhouse gas emissions and ensure that the LCFS does not disproportionately impact low-income communities.

AB 32 mandated several safeguards to ensure equity and protect low-income communities in California from potential adverse impacts associated with the act's implementation. Section 38562(b)(2) of California Health and Safety Code requires that CARB design regulations "in a manner that is equitable" and "[ensure] that activities undertaken to comply with the regulations do not disproportionately impact low-income communities" to the extent feasible.[209] Section 38562(b)(2) also mandates that CARB "consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."[210] Section 38562.5 further mandates that, "when adopting rules and regulations pursuant to this division to achieve emissions reductions beyond the state greenhouse gas emissions limit and to protect the state's most impacted and disadvantaged

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[207] Environmental justice critiques of pollution trading schemes for their tendency to result in localized pollution that disproportionately impacts low-income and people of color communities are longstanding. *See, e.g., Environmental Justice Advocates Blast Emissions Trading Guide*, 10 INSIDE EPA'S CLEAN AIR REPORT 9, 6-7 (April 29, 1999), *available at* https://www.jstor.org/stable/48520963; Lily N. Chinn, *Can the Market Be Fair and Efficient? An Environmental Justice Critique of Emissions Trading*, 26 *Ecol. L. Quart.* 1 (1999), http://www.jstor.org/stable/24114004; Letter to the Biden-Harris Transition Team Re: EPA Administrator Appointment from Over 70 Environmental Justice Groups (December 2, 2020), *available at* https://1bps6437gg8c169i0y1drtgz-wpengine.netdna-ssl.com/wp-content/uploads/2020/12/2020-12-2-Nichols-letter.pdf.

[208] LCFS fuels originating from factory dairy farms include electricity, renewable natural gas, hydrogen, bio-compressed natural gas, bio-liquefied natural gas, and bio-liquefied-regasified-and recompressed (Bio-L-CNG). CAL. CODE REGS. TIT. 17, § 95481 (defining biogas, biomethane, and all LCFS fuels produced from biomethane).

[209] CAL. HEALTH & SAFETY CODE § 38562(b)(2). See also *Ass'n of Irritated Residents v. State Air Res. Bd.*, 206 Cal. App. 4th 1487, 1489 (2012).

[210] CAL. HEALTH & SAFETY CODE § 38562.

communities," the state board shall consider social costs.[211] CARB is currently out of compliance with each of these mandates and, accordingly, must cease and desist operation of the LCFS factory farm gas pathways unless and until it comes into compliance.

Section 38562(b)(2)'s charge to protect "low-income communities" includes "persons and families whose income does not exceed 120 percent of the area median income, adjusted for family size [...] in accordance with adjustment factors adopted and amended from time to time by the United States Department of Housing and Urban Development pursuant to Section 8 of the United States Housing Act of 1937."[212] Area median income covers "the median family income of a geographic area of the state."[213] The residents of the San Joaquin Valley are precisely the low-income communities Sections 38562 seek to protect. As demonstrated above, the LCFS factory farm gas pathways have a disproportionate adverse impact on the basis of race and income, demonstrating CARB's failure to have designed the regulations in a manner that is equitable.

Finally, 38562(b)(2) requires consideration of overall societal benefits. CARB must amend the LCFS regulation to account for this and remedy these violations to come into compliance with AB 32. In Section 38562.5 of California Health and Safety Code, social costs means "an estimate of the economic damages, including, but not limited to, changes in net agricultural productivity; impacts to public health; climate adaptation impacts, such as property damages from increased flood risk; and changes in energy system costs, per metric ton of greenhouse gas emission per year."[214] The greenhouse gas emissions and associated co-pollutants from the production of factory farm gas has significant socials costs to public health, as discussed extensively in parts III and IV(B). Amending the LCFS to account for a serious consideration of the social costs of the emissions associated with both factory farm gas and the conventional fuels that generate deficits would not only bring CARB into compliance with Section 38562.5, but it would assist CARB in understanding and evaluating the inequitable distribution of adverse impacts in a manner that supports civil rights compliance, a described above.

V. CARB'S LACK OF TRANSPARENCY DENIES THE PUBLIC THE ABILITY TO REVIEW AND CHALLENGE EXISTING REGULATIONS, INCLUDING THE LCFS PATHWAYS FOR BIOMETHANE FROM DAIRY AND SWINE MANURE.

Meaningful public participation and advocacy regarding the impacts of the LCFS program have been hindered by CARB's lack of transparency. Locations of facilities purchasing the credits generated by factory farm dairies in the San Joaquin Valley are unknown to the public and attempts to obtain trading data through the California Public Records Act has produced only heavily redacted records. Without readily available trading data, it is difficult to determine potential disparate impacts caused by both the incentives produced by credit generation and the offsetting role of credit trading within the LCFS program. Community groups and advocates should not have

[211] CAL. HEALTH & SAFETY CODE § 38562.5. Note that the 2018 amendments made the LCFS generate reductions beyond the statewide limit.
[212] CAL. HEALTH & SAFETY CODE § 50093.
[213] *Id*.
[214] CAL. HEALTH & SAFETY CODE § 38506.

to seek out this information to conduct their own analyses of CARB's potentially discriminatory policies. CARB's control over the trading data places the agency in the best position to assess the disparate impact produced by the LCFS. Moreover, CARB has a clear, affirmative duty to comply with AB 32, CA 11135, and Title VI and prevent a disparate impact from its policies and practices.

VI. CONCLUSION

Since the Legislature enacted AB 32 in 2006, both the predicted and actual climate change-related harms have become more dire.[215] The methane generated by factory farm dairies in California alone accounts for approximately 45 percent of the state's total methane emissions that contribute to these harms.[216] And the Intergovernmental Panel on Climate Change recently declared a climate code red when it called for strong, sustained, and rapid methane reductions to stabilize our climate.[217]

CARB must grant this petition and reform the LCFS. Rather than allow factory farm gas reductions to substitute for emissions increases from the transportation sector, CARB should amend the LCFS to exclude factory farm gas from this pollution trading scheme.[218] If CARB instead decides to continue allowing Big Oil & Gas to offset their transportation fuel emissions with factory farm gas, then CARB must (1) ensure that the LCFS does not inflict disparate impacts in violation of CA 11135, CA 12955, and Title VI of the Civil Rights Act; and (2) adopt all alternative LCFS amendments requested here to ensure LCFS integrity and protections for rural communities.

CARB must take this opportunity to reform a pollution trading scheme that has gone off the rails. The LCFS incentivizes more of that which it purports to control, allows inflated and illusory credits from factory farm gas to authorize more emissions from transportation fuel, refuses to acknowledge the truth that liquefied manure is intentionally created and not somehow naturally occurring awaiting only abatement, and authorizes non-additional credits generated at projects receiving massive incentives from public funds and the Aliso Canyon settlement agreement. This pollution trading scheme merely shifts emissions; it benefits Big Oil & Gas to allow more pollution from their transportation fuels. It benefits, entrenches, and expands the industrial dairy and pig industry with a revenue stream more valuable than milk. And it benefits the gas utilities that

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[215] *See, e.g.*, Thomas Fuller and Christopher Flavelle, *A Climate Reckoning in Fire-Stricken California*, N.Y. TIMES (Sept. 10, 2020), https://www.nytimes.com/2020/09/10/us/climate-change-california-wildfires.html; Christopher Flavelle, *How California Became Ground Zero for Climate Disasters*, N.Y. TIMES (Sept. 20, 2020), https://www.nytimes.com/2020/09/20/climate/california-climate-change-fires.html; Nadja Popovich, *How Severe Is the Western Drought? See For Yourself.*, N.Y. TIMES (Sept. 20, 2020), https://www.nytimes.com/interactive/2021/06/11/climate/california-western-drought-map.html.

[216] CAL. AIR RES. BD., Short-Lived Climate Pollutant Reduction Strategy 56, Figure 4 (March 2017), https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

[217] IPCC, *Climate Change 2021: the Physical Science Basis, which represents the findings of Working Group I and its contribution to the Sixth Assessment Report*, *available at* https://www.ipcc.ch/report/ar6/wg1/.

[218] Petitioners do not suggest that methane from industrial dairy and pig facilities should be unabated. CARB has authority to adopt mandatory regulations to achieve up to a 40 percent reduction from manure methane emissions pursuant to Health & Safety Code § 39730.5.

desperately attempt to perpetuate the combustion of gas in the face of a future where electrified buildings and transportation are the only routes to achieve California's climate goals. San Joaquin Valley communities should not suffer the discriminatory effects of CARB's pollution trading scheme, and CARB should grant this petition and deliver environmental justice.

Respectfully Submitted this 27th of October, 2021,

Ruthie Lazenby
Vermont Law School
Environmental Justice Clinic

Brent Newell
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Tom Frantz
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Food & Water Watch

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Christine Ball-Blakely
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I. APPENDICES

A. APPENDIX A: PROPOSED AMENDMENTS TO THE LCFS TO REMOVE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE

§ 95488.3. Calculation of Fuel Pathway Carbon Intensities

(a) Calculating Carbon Intensities. Fuel pathway applicants and the Executive Officer will evaluate all pathways based on life cycle greenhouse gas emissions per unit of fuel energy, or carbon intensity, expressed in gCO2e/MJ. For this analysis, the fuel pathway applicant must use CA-GREET3.0 model (including the Simplified CI Calculators derived from that model) or another model determined by the Executive Officer to be equivalent or superior to CA-GREET3.0.

(b) CA-GREET3.0. The CA-GREET3.0 model (August 13, 2018) contains emission factors for calculating greenhouse gas emissions from site-specific inputs to fuel pathways and standard values for parts of the life cycle not included in applicant-specific data submission. The model is open source and publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and is incorporated herein by reference. CA-GREET3.0 includes contributions from the Oil Production Greenhouse Gas Estimator (OPGEE2.0) model (for emissions from crude extraction) and Global Trade Analysis Project (GTAP-BIO) together with the Agro-Ecological Zone Emissions Factor (AEZ-EF) model for land use change (LUC).

Tier 1 Simplified CI Calculators, which incorporate emission factors and life cycle inventory data from the CA-GREET3.0 model, are used to calculate carbon intensities for Tier 1 pathways. The eight Simplified CI Calculators listed below are publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and are incorporated herein by reference:

(1) Tier 1 Simplified CI Calculator for Starch and Fiber* Ethanol (August 13, 2018)

(2) Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol (August 13, 2018)

(3) Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel (August 13, 2018)

(4) Tier 1 Simplified CI Calculator for LNG and L-CNG from North American Natural Gas (August 13, 2018)

(5) Tier 1 Simplified CI Calculator for Biomethane from North American Landfills (August 13, 2018)

(6) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge (August 13, 2018)

~~(7) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste (August 13, 2018)~~

© OPGEE2.0. The OPGEE2.0 model is used to generate carbon intensities for crude oil used in the production of ultra-low sulfur diesel (ULSD) and California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).

(d) Accounting for Land Use Change. The Executive Officer calculates LUC effects for certain crop-based biofuels using the GTAP model (modified to include agricultural data and termed GTAP-BIO) and the AEZ-EF model. LUC values for six feedstock/finished biofuel combinations are provided in Table 6 below. The Executive Officer may use the same modeling framework to assess LUC values for other fuel or feedstock combinations, not currently found in Table 6, as part of processing a pathway application. Alternatively, the Executive Officer may require a fuel pathway applicant to use one of the values in Table 6, if the Executive Officer deems that value appropriate to use for a fuel or feedstock combination not currently listed in Table 6.

Table 6. Land Use Change Values for Use in CI Determination

Biofuel	LUC (gCO<2>/MJ
Corn Ethanol	19.8
Sugarcane Ethanol	11.8
Soy Biomass-Based Diesel	29.1
Canola Biomass-Based Diesel	14.5
Grain Sorghum Ethanol	19.4
Palm Biomass-Based Diesel	71.4

* Fiber in this case refers to corn and grain sorghum fiber exclusively.

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(f) Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion ~~may~~ shall not be certified.~~ With a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:~~

~~(A) A biogas control system, or digester, is used to capture biomethane from manure management on **dairy** cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.~~

~~(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.~~

B. APPENDIX B: PROPOSED AMENDMENTS TO REFORM THE LCFS PATHWAYS FOR BIOMETHANE FROM DAIRY AND SWINE MANURE

§ 95488.3. Calculation of Fuel Pathway Carbon Intensities

(a) Calculating Carbon Intensities. Fuel pathway applicants and the Executive Officer will evaluate all pathways based on life cycle greenhouse gas emissions per unit of fuel energy, or carbon intensity, expressed in gCO2e/MJ. For this analysis, the fuel pathway applicant must use CA-GREET3.0 model (including the Simplified CI Calculators derived from that model) or another model determined by the Executive Officer to be equivalent or superior to CA-GREET3.0.

(b) CA-GREET3.0. The CA-GREET3.0 model (August 13, 2018) contains emission factors for calculating greenhouse gas emissions from site-specific inputs to fuel pathways and standard values for parts of the life cycle not included in applicant-specific data submission. The model is open source and publicly available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm and is incorporated herein by reference. CA-GREET3.0 includes contributions from the Oil Production Greenhouse Gas Estimator (OPGEE2.0) model (for emissions from crude extraction) and Global Trade Analysis Project (GTAP-BIO) together with the Agro-Ecological Zone Emissions Factor (AEZ-EF) model for land use change (LUC).

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(6) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge (August 13, 2018)

(7) Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste (August 13, 2018)

(c) OPGEE2.0. The OPGEE2.0 model is used to generate carbon intensities for crude oil used in the production of ultra-low sulfur diesel (ULSD) and California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).

(d) Accounting for Land Use Change. The Executive Officer calculates LUC effects for certain crop-based biofuels using the GTAP model (modified to include agricultural data and termed GTAP-BIO) and the AEZ-EF model. LUC values for six feedstock/finished biofuel combinations are provided in Table 6 below. The Executive Officer may use the same modeling framework to assess LUC values for other fuel or feedstock combinations, not currently found in Table 6, as part of processing a pathway application. Alternatively, the Executive Officer may require a fuel pathway applicant to use one of the values in Table 6, if the Executive Officer deems that value appropriate to use for a fuel or feedstock combination not currently listed in Table 6.

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Grain Sorghum Ethanol	19.4
Palm Biomass-Based Diesel	71.4

* Fiber in this case refers to corn and grain sorghum fiber exclusively.

<u>(e) Accounting for life cycle emissions for all fuel pathways from manure feedstock. In calculating the carbon intensity of any fuel derived from manure feedstock, the Executive Officer shall include all upstream and downstream greenhouse gas emissions from all activities associated with manure production, including but not limited to feed emissions, mobile and stationary source combustion emissions, enteric emissions, emissions from composting digestate solids, emissions following land application, and indirect source emissions.</u>

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(f) Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:

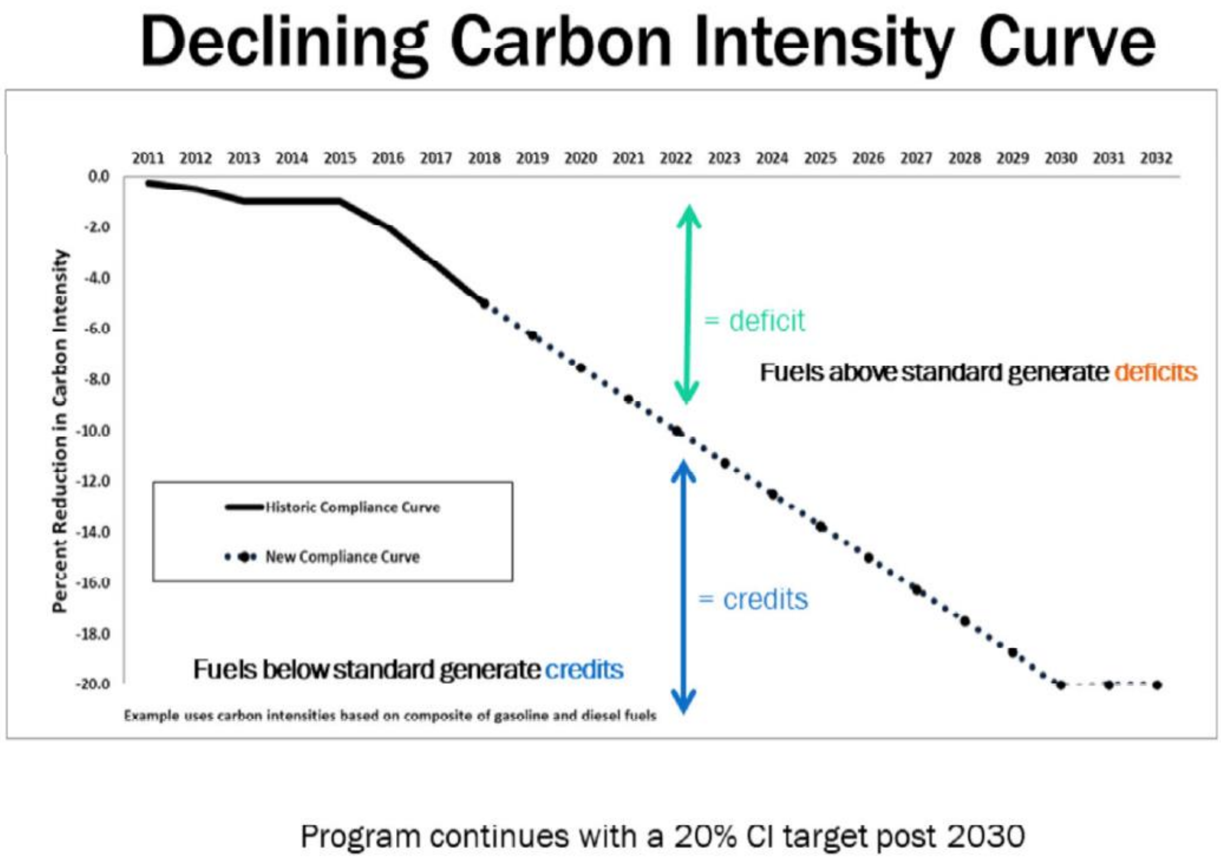
(A) A biogas control system, or digester, is used to capture biomethane from manure management on dairy cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.

(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane<u>, and any other greenhouse gas emission reduction that otherwise would occur</u>.

<u>(C) The fuel pathway derived from biomethane from dairy cattle or swine manure digestion pursuant to section 95488.3(e) does not (1) contribute any amount of nitrogen oxides, volatile organic compounds, sulfur oxides, ammonia, or particulate matter with an aerodynamic diameter of ten microns or less into the ambient air; (2) cause or contribute to groundwater or surface water pollution or degradation; (3) intensify water demand in areas medium and high priority water basins; or (4) intensify or exacerbate any negative local impacts including but not limited to odor and insects.</u>

C. APPENDIX C: TABLES AND FIGURES

Figure 1: Declining Annual Benchmark for the LCFS program.[219]



[219] CAL. AIR RES. BD., *LCFS Basics* (2019), *available at* https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf (last visited Oct. 12, 2021).

Table 1. Credit Value Calculator from LCFS Data Dashboard.[220]

Credit Value Calculator:
Estimated LCFS Premium at Sample LCFS Credit Prices

Alternative Fuel Premiums at Sample LCFS Credit Prices
($/gal gasoline-equivalent for fuels used as gasoline substitutes)

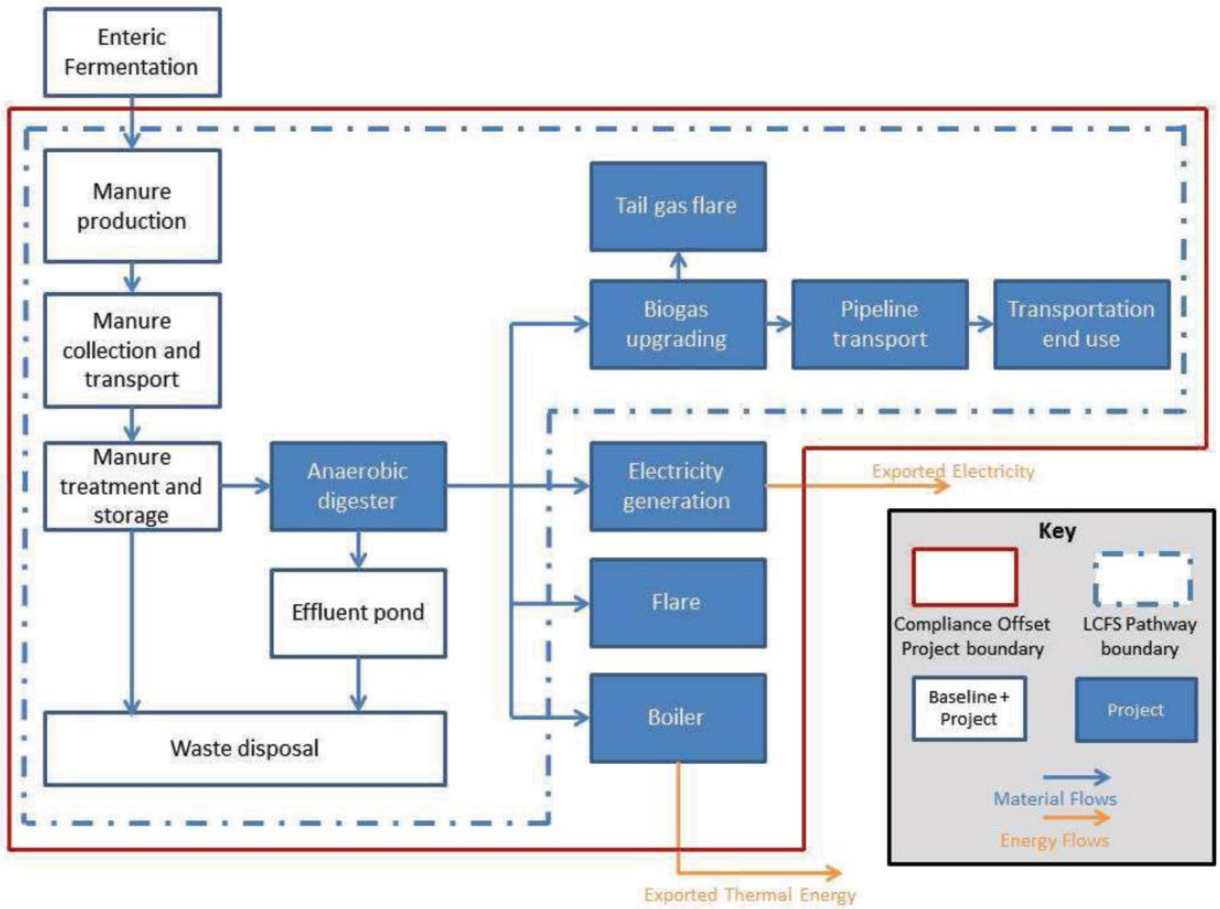
CI Score (gCO2e/MJ)	Credit Price $196	$80	$100	$120	$160	$200
-273	$8.31	$3.39	$4.24	$5.09	$6.79	$8.48
10	$1.89	$0.77	$0.96	$1.16	$1.54	$1.93
20	$1.66	$0.68	$0.85	$1.02	$1.36	$1.70
30	$1.44	$0.59	$0.73	$0.88	$1.17	$1.46
40	$1.21	$0.49	$0.62	$0.74	$0.99	$1.23
50	$0.98	$0.40	$0.50	$0.60	$0.80	$1.00
60	$0.75	$0.31	$0.38	$0.46	$0.62	$0.77
70	$0.53	$0.22	$0.27	$0.32	$0.43	$0.54
80	$0.30	$0.12	$0.15	$0.18	$0.25	$0.31
90	$0.07	$0.03	$0.04	$0.04	$0.06	$0.07
100	-$0.15	-$0.06	-$0.08	-$0.09	-$0.13	-$0.16
110	-$0.38	-$0.16	-$0.19	-$0.23	-$0.31	-$0.39
120	-$0.61	-$0.25	-$0.31	-$0.37	-$0.50	-$0.62
130	-$0.83	-$0.34	-$0.43	-$0.51	-$0.68	-$0.85
140	-$1.06	-$0.43	-$0.54	-$0.65	-$0.87	-$1.08
150	-$1.29	-$0.53	-$0.66	-$0.79	-$1.05	-$1.32
CaRFG* ($/gallon) 100.82	-$0.139	-$0.057	-$0.071	-$0.085	-$0.113	-$0.142

* Maximum pass-through cost for gasoline. Assumes a blend of CARBOB with 10 volume percent ethanol at a CI of 79.9 g/MJ. Ethanol at 79.9 g/MJ is assumed to receive no LCFS premium.

Last Modified 05/31/2019

[220] Data Dashboard, CAL. AIR RES. BD. Figure 7, *https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm* (last visited Oct. 20, 2021).

Figure 2. CARB schematic of the system boundaries for upgraded biogas (biomethane) from Anaerobic digestion of Dairy Manure.[221]



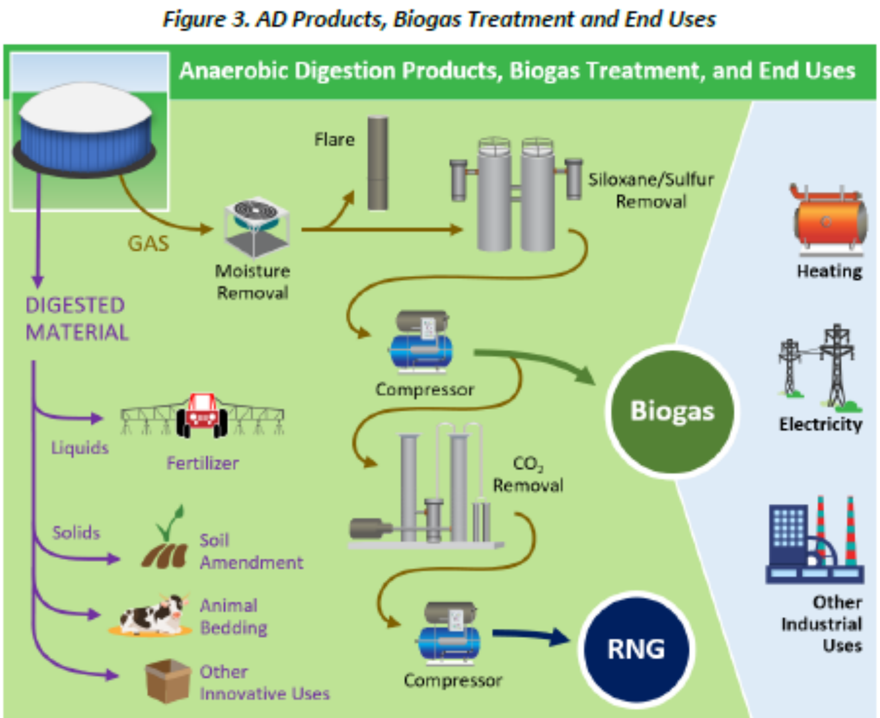
[221] CAL. AIR RES. BD., *supra* note 96 at 13.

Figure 3. Waste Management Hierarchy chart for manure management.[222]

Waste Management Hierarchy	Attribute	Applicability in animal manure management
Avoidance	Most preferred option. Preventive. Use of less hazardous materials in the design and manufacture of products. Develop strategies for cleaner and environmentally friendly production	While the production of wastes cannot be completely eliminated in animal production, the production can be made cleaner and environmentally friendly
Reduction of wastes	Second most preferred option. Preventive. Actions to make changes in the type of materials being used for specific products. This approach contributes to effective savings of natural resources	Applicable
Reuse	Predominantly ameliorative and partly preventive. The waste is collected during the production phase and fed back into the production process. Reduce the amount of wastes generated and the cost of production. Desirable.	Applicable
Recycle	Predominantly ameliorative and partly preventive. The waste materials are collected and processed, and used in the production of new products. The process prevents pollution. Desirable.	Applicable
Energy recovery	Predominantly assimilative and partly ameliorative. This is also called waste to energy conversion. Wastes are converted to usable energy forms such as heat, light, electricity, etc. Desirable.	Applicable
Treatment	Predominantly assimilative and partly ameliorative. Desirable.	Applicable
Sustainable disposal	Disposal is the least preferred option in the waste management hierarchy and should be avoided.	Possible but not preferred

[222] Gabriel Adebayo Malomo et al., *Sustainable Animal Manure Management Strategies and Practices*, 9 (Aug. 29, 2018) https://www.intechopen.com/books/agricultural-waste-and-residues/sustainable-animal-manure-management-strategies-and-practices.

Figure 4. Diagram of downstream uses of digested materials.[223]



[223] ENV'T. PROT. AGENCY, *An Overview of Renewable Natural Gas from Biogas* 4 (July 2020) https://www.epa.gov/sites/production/files/2020-07/documents/lmop_rng_document.pdf.

Figure 5. Rise in Average Monthly Credit Price since 2013.[224]

Table 2. The California dairy industry experienced negative average residuals in 2015 and 2016, indicating a lack of profit in these years.[225]

Table 1.6: California Dairy Farm Annual Unit Costs of Production by Category 2014-2017

Dairy Input	2014 $/cwt	2015 $/cwt	2016 $/cwt	2017 $/cwt
Feed	$11.05	$10.46	$9.22	$8.77
Hired Labor	$1.56	$1.70	$1.74	$1.87
Herd Replacement	$1.37	$2.12	$2.10	$1.88
Operating Costs	$2.88	$2.93	$2.92	$3.06
Milk Marketing	$0.56	$0.56	$0.55	$0.55
Total Costs	**$17.42**	**$17.77**	**$16.53**	**$16.13**
Average Mailbox Price	**$22.37**	**$15.94**	**$15.56**	**$16.99**
Price – Costs (Residual)	**$4.95**	**-$1.83**	**-$0.97**	**$0.86**

Source: CDFA California Dairy Cost of Production Annuals
https://www.cdfa.ca.gov/dairy/dairycop_annual.html

224 AcMoody, *supra* note 128 at 4.
225 Matthews, *supra* note 130 at 20.

Figure 6. Groundwater contamination sites in Kern County.[226]

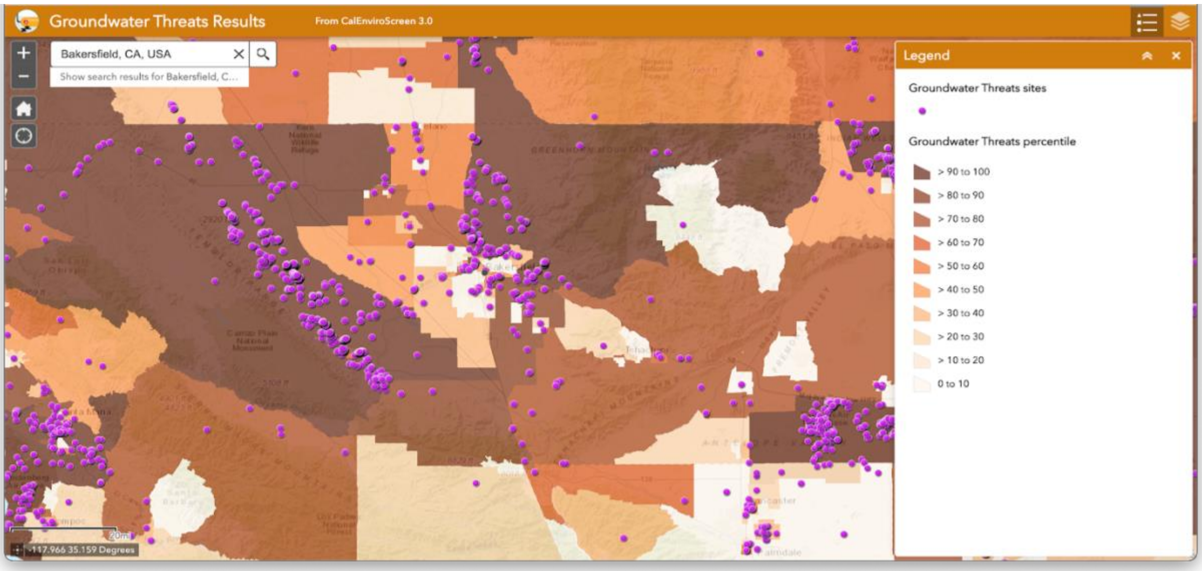
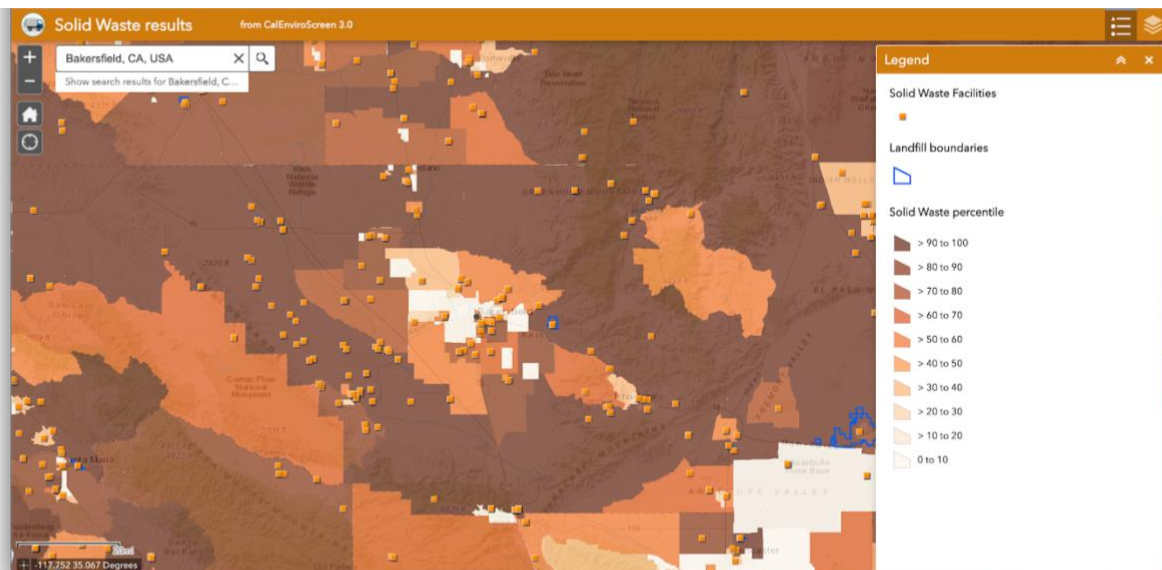
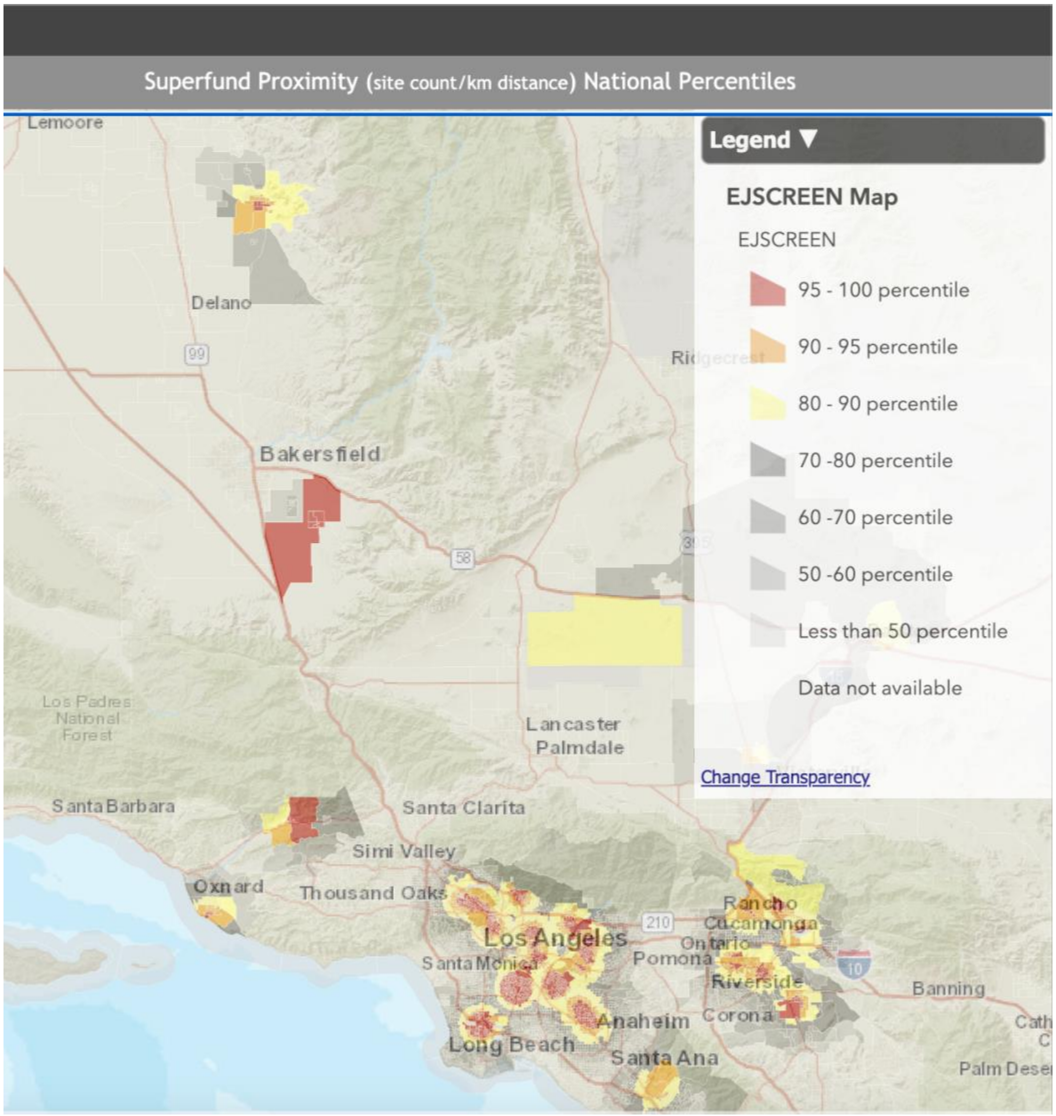


Figure 7. Solid waste contamination in Kern County.[227]



[226] CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, *supra* note 29.
[227] *Id.*

Figure 8. Superfund site near Bakersfield, CA.[228]



[228] *EJScreen*, ENV'T. PROT. AGENCY, https://www.epa.gov/ejscreen (last accessed Apr. 10, 2021).

Table 3. A list of the top counties that sell cow's milk ($ billions), the majority of which are in California.[229]

Top Counties in Cow's Milk Sales ($ billions)	
Tulare, CA	1.8
Merced, CA	1.1
Gooding, ID	0.7
Stanislaus, CA	0.7
Kings, CA	0.6
Kern, CA	0.5
Yakima, WA	0.4
Lancaster, PA	0.4
Fresno, CA	0.4
San Joaquin, CA	0.4

Does not include counties withheld to avoid disclosing individual data.

[229] U.S. DEP'T OF AGRIC., *Dairy Cattle and Milk Production* at 2 (Oct. 2014) https://www.nass.usda.gov/Publications/Highlights/2014/Dairy_Cattle_and_Milk_Production_Highlights.pdf.

Table 4. Demographic data on Kern, Kings, Madera, and San Joaquin Counties.[230]

Fact	Kern County, California	Kings County, California	Madera County, California	San Joaquin County, California
Population estimates, July 1, 2019, (V2019)	900,202	152,940	157,327	762,148
Population estimates base, April 1, 2010, (V2019)	839,621	152,974	150,834	685,306
Population, percent change - April 1, 2010 (estimates base) to	7.20%	0.00%	4.30%	11.20%
Population, Census, April 1, 2010	839,631	152,982	150,865	685,306
Persons under 5 years, percent	7.60%	7.60%	7.30%	6.90%
Persons under 18 years, percent	28.80%	27.00%	27.40%	26.80%
Persons 65 years and over,	11.20%	10.50%	14.30%	13.10%
Female persons, percent	48.80%	44.90%	51.80%	50.10%
White alone, percent	82.30%	80.80%	85.90%	66.10%
Black or African American alone,	6.30%	7.50%	4.20%	8.30%
American Indian and Alaska Native alone, percent	2.60%	3.20%	4.40%	2.00%
Asian alone, percent	5.40%	4.40%	2.60%	17.40%
Native Hawaiian and Other Pacific Islander alone, percent	0.30%	0.40%	0.30%	0.80%
Two or More Races, percent	3.20%	3.70%	2.60%	5.50%
Hispanic or Latino, percent	54.60%	55.30%	58.80%	42.00%
White alone, not Hispanic or Latino, percent	32.80%	31.30%	33.20%	30.50%
Veterans, 2015-2019	35,594	9,684	6,317	29,013
Foreign born persons, percent,	19.90%	18.90%	20.20%	23.30%
Housing units, July 1, 2019,	302,898	46,965	51,438	248,636
Owner-occupied housing unit rate, 2015-2019	58.30%	52.30%	64.10%	56.60%
Median value of owner-occupied housing units, 2015-2019	213,900	215,900	251,200	342,100
Median selected monthly owner costs -with a mortgage, 2015-2019	$1,527	$1,459	$1,551	$1,907
Median selected monthly owner costs -without a mortgage, 2015-	$452	$446	$478	$523
Median gross rent, 2015-2019	$978	$990	$1,014	$1,208
Building permits, 2019	2,261	409	644	3,499
Households, 2015-2019	270,282	43,452	44,881	228,567
Persons per household, 2015-	3.17	3.13	3.28	3.17
Living in same house 1 year ago, percent of persons age 1 year+,	86.10%	81.90%	87.90%	86.80%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	44.20%	41.50%	45.30%	40.90%
High school graduate or higher, percent of persons age 25 years+,	74.10%	73.40%	71.90%	79.30%
Bachelor's degree or higher, percent of persons age 25 years+,	16.40%	14.70%	14.60%	18.80%
With a disability, under age 65 years, percent, 2015-2019	7.80%	8.60%	8.70%	8.70%
Persons without health insurance, under age 65 years,	9.00%	8.50%	10.70%	7.80%
In civilian labor force, total, percent of population age 16	58.00%	51.80%	54.30%	60.30%
In civilian labor force, female, percent of population age 16	52.40%	51.50%	47.90%	53.60%
Total accommodation and food services sales, 2012 ($1,000)	1,092,151	378,595	150,065	808,606
Total health care and social assistance receipts/revenue,	3,675,000	587,818	760,956	3,447,722
Median household income (in 2019 dollars), 2015-2019	$53,350.00	$57,848.00	$57,585.00	$64,432.00
Per capita income in past 12 months (in 2019 dollars), 2015-	$23,326.00	$22,373.00	$22,853.00	$27,521.00
Persons in poverty, percent	19.00%	16.00%	17.60%	13.60%

[230] *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/US/PST045219 (last visited Apr. 10, 2021).

Table 5. Demographic data on Merced, Tulare, Fresno, and Stanislaus Counties.[231]

Fact	Merced County, California	Tulare County, California	Fresno County, California	Stanislaus County, California
Population estimates, July 1, 2019, (V2019)	277,680	466,195	999,101	550,660
Population estimates base, April 1, 2010, (V2019)	255,796	442,182	930,507	514,450
Population, percent change - April 1, 2010 (estimates base) to July 1, 2019, (V2019)	8.60%	5.40%	7.40%	7.00%
Population, Census, April 1, 2010	255,793	442,179	930,450	514,453
Persons under 5 years, percent	7.70%	7.80%	7.60%	7.10%
Persons under 18 years, percent	29.30%	30.50%	28.20%	27.00%
Persons 65 years and over, percent	11.40%	11.60%	12.60%	13.40%
Female persons, percent	49.50%	50.00%	50.10%	50.40%
White alone, percent	82.20%	88.20%	76.60%	83.30%
Black or African American alone, percent	3.90%	2.20%	5.80%	3.50%
American Indian and Alaska Native alone, percent	2.50%	2.80%	3.00%	2.00%
Asian alone, percent	7.80%	4.00%	11.10%	6.10%
Native Hawaiian and Other Pacific Islander alone, percent	0.40%	0.20%	0.30%	0.90%
Two or More Races, percent	3.20%	2.70%	3.20%	4.20%
Hispanic or Latino, percent	61.00%	65.60%	53.80%	47.60%
White alone, not Hispanic or Latino, percent	26.50%	27.70%	28.60%	40.40%
Veterans, 2015-2019	9,225	14,633	36,125	21,051
Foreign born persons, percent, 2015-2019	26.30%	21.80%	21.20%	20.30%
Housing units, July 1, 2019, (V2019)	86388	151603	336473	182978
Owner-occupied housing unit rate, 2015-2019	52.20%	57.10%	53.30%	57.80%
Median value of owner-occupied housing units, 2015-2019	252,700	205,000	255,000	291,600
Median selected monthly owner costs -with a mortgage, 2015-2019	1,493	1,420	1,631	1,702
Median selected monthly owner costs -without a mortgage, 2015-2019	$460.00	$421.00	$484.00	$503.00
Median gross rent, 2015-2019	$1,021.00	$942.00	$998.00	$1,155.00
Building permits, 2019	948	1,872	3,393	699
Households, 2015-2019	80,008	138,238	307,906	173,898
Persons per household, 2015-2019	3.32	3.3	3.14	3.09
Living in same house 1 year ago, percent of persons age 1 year+, 2015-2019	86.60%	88.60%	85.80%	87.90%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	53.30%	51.30%	44.60%	42.90%
High school graduate or higher, percent of persons age 25 years+, 2015-2019	69.10%	70.80%	76.00%	78.90%
Bachelor's degree or higher, percent of persons age 25 years+, 2015-2019	13.80%	14.60%	21.20%	17.10%
With a disability, under age 65 years, percent, 2015-2019	9.10%	8.20%	9.20%	9.00%
Persons without health insurance, under age 65 years, percent	9.00%	9.00%	8.80%	7.10%
In civilian labor force, total, percent of population age 16 years+, 2015-2019	59.60%	59.00%	60.90%	60.90%
In civilian labor force, female, percent of population age 16 years+, 2015-2019	51.00%	51.10%	55.20%	53.40%
Total accommodation and food services sales, 2012 ($1,000)	232,910	451,880	1,226,169	705,698
Total health care and social assistance receipts/revenue, 2012 ($1,000)	788114	1610236	5325615	3634960
Median household income (in 2019 dollars), 2015-2019	$53,672.00	$49,687.00	$53,969.00	$60,704.00
Per capita income in past 12 months (in 2019 dollars), 2015-2019	$23,011.00	$21,380.00	$24,422.00	$26,258.00
Persons in poverty, percent	17.00%	18.90%	20.50%	13.00%

[231] *Id.*

Table 6. Quick facts on potential pathogens found in digestate and links for further information.[232]

Pathogen	**Effects**	**For more information**
Cryptosporidium parvum	"[M]icroscopic parasite that causes the diarrheal disease cryptosporidiosis."	https://www.cdc.gov/parasites/crypto/index.html
Salmonella spp	"Most people with Salmonella infection have diarrhea, fever, and stomach cramps."	https://www.cdc.gov/salmonella/general/index.html
norovirus	"Norovirus is a very contagious virus that causes vomiting and diarrhea."	https://www.cdc.gov/norovirus/index.html
Streptococcus pyogenes	"[C]an cause both noninvasive and invasive disease, as well as nonsuppurative sequelae. "	https://www.cdc.gov/groupastrep/diseases-hcp/index.html
E. coli enteropathogenic (EPEC)	"[A]re gram-negative bacteria that inhabit the gastrointestinal tract. Most strains do not cause illness. Pathogenic E. coli are categorized into pathotypes on the basis of their virulence genes. Six pathotypes are associated with diarrhea	https://wwwnc.cdc.gov/travel/yellowbook/2020/travel-related-infectious-diseases/escherichia-coli-diarrheagenic

[232] *Parasites – Cryptosporidium (also known as "Crypto")*, CDC, https://www.cdc.gov/parasites/crypto/index.html (last updated July 1, 2019); *Salmonella*, CDC, https://www.cdc.gov/salmonella/general/index.html (last updated Dec 5, 2019); *Norovirus*, CDC, https://www.cdc.gov/norovirus/index.html (last updated Mar. 5, 2021); *Group A Streptococcal (GAS) Disease*, CDC, https://www.cdc.gov/groupastrep/diseases-hcp/index.html (last updated May 7, 2020); Alison Winstead et al., *Escherichia coli, Diarrheagenic*, CDC, https://wwwnc.cdc.gov/travel/yellowbook/2020/travel-related-infectious-diseases/escherichia-coli-diarrheagenic (last updated July 1, 2021); J. L. Cloud et al., *Identification of Mycobacterium spp. by Using a Commercial 16S Ribosomal DNA Sequencing Kit and Additional Sequencing Libraries*, 40(2) J. Clinical Microbiology 400, 400 (Feb. 2002); *Typhoid Fever and Paratyphoid Fever*, CDC, https://www.cdc.gov/typhoid-fever/index.html (last updated Aug. 22, 2018); *Fact Sheet: Clostridium spp*, WickhamLaboratories, https://wickhamlabs.co.uk/technical-resource-centre/fact-sheet-clostridium-spp/ (last visited May 5, 2021); Listeria (Listeriosis), CDC, https://www.cdc.gov/listeria/symptoms.html (Dec. 12, 2016).

	(diarrheagenic) […] enteropathogenic E. coli (EPEC)”	
Mycobacterium spp.	"Mycobacterium species are a group of acid-fast, aerobic, slow-growing bacteria. The genus comprises more than 70 different species, of which about 30 have been associated with human disease (23)."	https://www.ncbi.nlm.nih.gov/pmc/articles/PMC153382/#:~:text=Mycobacterium%20species%20are%20a%20group,the%20causative%20agent%20of%20tuberculosis
Salmonella typhi (followed by S. paratyphi)	"Typhoid fever and paratyphoid fever are life-threatening illnesses caused by Salmonella serotype Typhi and Salmonella serotype Paratyphi, respectively."	https://www.cdc.gov/typhoid-fever/index.html
Clostridium spp.	“Clostridia are one of the most commonly studied anaerobes that cause disease in humans”. Some of the species of Clostridium can cause: botulism, overgrow in the intestine compromising the inherent gut flora (potentially leading to colitis), tetanus, gas gangrene (myonecrosis), and toxic shock syndrome.	https://wickhamlabs.co.uk/technical-resource-centre/fact-sheet-clostridium-spp/
Listeria monocytogenes	"[C]an cause fever and diarrhea similar to other foodborne germs, but this type of Listeria infection is rarely diagnosed. Symptoms in people with invasive listeriosis, meaning the bacteria has spread beyond the gut, depend on whether the person is pregnant."	https://www.cdc.gov/listeria/symptoms.html

Attach. 4

Sent via email and U.S. certified mail:

January 26, 2022

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Re: Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program

Dear Ms. Lazenby and Mr. Newell,

Thank you for the petition for rulemaking,[1] submitted by Vermont Law School's Environmental Justice Clinic and Public Justice on behalf of the Association of Irritated Residents (AIR), Leadership Counsel for Justice & Accountability, Food & Water Watch, and Animal Legal Defense Fund, on October 27, 2021, to the California Air Resources Board (CARB).[2] CARB initially acknowledged receipt of the petition on November 8, 2021.[3] We appreciate that petitioners agreed to toll the deadline for response to the petition to January 28, 2022, while we took opportunities to discuss the petition with petitioners to better understand the concerns as well as the availability of supporting documentation.[4]

In your petition, you requested that CARB amend the Low Carbon Fuel Standard (LCFS) regulations found at Title 17, California Code of Regulations (CCR), sections 95480 through 95503. The LCFS regulations are authorized by the Global Warming Solutions Act of 2006

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[1] Submitted pursuant to Government Code, § 11340.6.

[2] The petition is available from CARB upon request.

[3] *See* letter from Mr. Matthew Botill, Chief, Industrial Strategies Division, CARB, to Ms. Ruthie Lazenby and Mr. Brent Newell, counsel for petitioners, attached as Exhibit A.

[4] *See* tolling agreement executed on December 6, 2021, attached as Exhibit B.

(Stats. 2006, Ch. 488, commonly referred to as AB 32.[5]) Specifically, the petition requests that CARB exclude all fuels derived from biomethane from dairy and swine manure from the LCFS, or, in the alternative, to reform the LCFS treatment of those fuels to account for additional greenhouse gas (GHG) emissions. The sections of the regulation that the petition requests that CARB amend are title 17, CCR, sections 95488.3 and 95488.9(f).

I want to take this opportunity to again thank the petitioners for taking the time to meet twice with me and other CARB senior management (on December 14, 2021, and also earlier this month on January 13, 2022). I also appreciate you, as a result of those meetings, sharing additional information for our consideration. I found the discussions productive and hope that they will continue through our public processes. I welcome continued engagement on the concerns raised in the petition as we consider the scope of potential amendments which will be discussed with all interested stakeholders as part of a public process we will initiate by first quarter of 2023. In the meantime, we welcome petitioners' input as we review and compile related materials.

CARB and petitioners share a commitment to ensure that CARB programs such as the LCFS continue to reduce air pollution disparities experienced by impacted communities, and that any adjustments to the regulation are carefully evaluated and done so through an open public process. Since 2019, LCFS staff have carefully reviewed comments received from various stakeholders (including the petitioners) in opposition to as well as support of the certification of animal manure biomethane pathways under the current LCFS regulation, and appreciate petitioners' contributions to strengthening that process.[6]

CARB further agrees it is important, as petitioners urge, to "ensure the LCFS provides environmental benefits and does not degrade water quality and interfere with efforts to improve air quality in the San Joaquin Valley."[7] CARB is committed as an organization to continue to use its authority (including the regulations it develops and implements such as the LCFS) to take action to protect the state's most impacted communities while reducing both GHG and other project-related criteria pollutants and toxics air contaminants. We invite ongoing dialogue with the petitioners as well as other stakeholders regarding information and data to ensure that the programs CARB develops and implements are delivering the intended benefits throughout the state and in communities.

As noted, we are committed to engaging with petitioners on their concerns, and committed to ensuring our programs focus on environmental justice and environmental integrity. However, the petition's specific requests for a near-term rulemaking are premature. I am therefore denying your petition in part and granting it in part for the reasons that follow.

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[5] *See, e.g.*, Health and Safety Code, sections 38560 and 38560.5.

[6] *See, e.g.*, June 26, 2020 *Comment Letter Re: Tier 2 Pathway Application: Application No. B0098; Calgren Dairy Fuels plus Circle A, Robert Vander Eyk, Legacy Ranch, Cornerstone, Sousa and Sousa, and Vander Poel Dairies*; and *CARB staff's public response.*

[7] Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program, page 5, October 27, 2021.

Relationship Between Ongoing AB 32 Scoping Plan Update and Potential Future LCFS Amendments

As petitioners are aware, CARB is coordinating an ongoing public process to develop an update of California's statewide strategy to achieve its climate change emissions reduction targets. This statewide strategy, known as the "Scoping Plan," is due to be considered by our Board in 2022.[8] The Scoping Plan is the statewide climate change strategy "for achieving the maximum technologically feasible and cost-effective reductions of greenhouse gas emissions" focusing on evaluating the integration of incentives, programs, and regulations to achieve the state's climate targets.[9] CARB has convened the AB 32 Environmental Justice Advisory Committee to consult and advise on the development of the 2022 Scoping Plan update. As a part of their advisory role, the Environmental Justice Advisory Committee will be conducting community engagement.

The first Scoping Plan was adopted by the Board in 2008, and the most recent update was adopted in late 2017. In June 2021, CARB began the process for the next update to the Scoping Plan for Board consideration in late 2022. Materials related to the ongoing public process, including workshop notices, relevant documents, and public feedback received, are available on our website.[10] As part of the 2022 Scoping Plan update, staff will consider legislative statutory direction, the Governor's Executive Orders, the latest science, and recommendations from the AB 32 Environmental Justice Advisory Committee and all other stakeholders on how to transition away from combustion of fossil fuels in all sectors of the economy. The LCFS has been included in past AB 32 climate change scoping plans as part of the mix of policies designed to drive emissions reductions from the transportation sector. That sector continues to be our largest source of greenhouse gases and harmful local air pollution.

We expect the 2022 Scoping Plan update to identify potential changes necessary to deploy clean fuels and technologies across the economy in order to achieve the state's climate targets. This may ultimately require changes to existing programs, such as the LCFS, or the identification of new programs. But the general direction of such revised or new programs will be informed by recommendations included in the final 2022 Scoping Plan update to ensure California has a holistic, fully-integrated, economy-wide state strategy for meeting its GHG reduction targets.

Past experience with our Scoping Plans is illustrative: The 2017 Scoping Plan update provided recommendations to strengthen LCFS statewide carbon intensity benchmarks in order to help the state achieve our 2030 GHG emissions reduction target of 40 percent below 1990 emissions levels. Following those recommendations, CARB staff proposed LCFS amendments in 2018, which significantly strengthened the program's regulatory targets –

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[8] AB 32 directs CARB to develop, and update at least once every five years, the overarching climate change strategy known by the statutory term "scoping plan." *See* Health and Safety Code, § 38561.

[9] *Id.*

[10] *https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/scoping-plan-meetings-workshops*

from a 10 percent average reduction in statewide transportation fuel lifecycle carbon intensity (CI) by 2020, to a 20 percent CI reduction by 2030. Those LCFS amendments grew out of an extensive informal public stakeholder feedback process launched in 2016,[11] and were formally proposed and eventually adopted in 2018.[12] As required by law, CARB in amending these regulations carried out an environmental analysis pursuant to the California Environmental Quality Act, as well as an economic impact analysis required for major regulations.[13] By the time CARB submitted the final Board approved regulatory package to the Office of Administrative Law, interested stakeholders had provided input on the proposed concepts and amendments through more than two dozen public workshops or working meetings. The proposed amendments were introduced for public and Board member discussion at two Board hearings, and CARB staff responded to hundreds of public comments submitted.

Therefore, it is premature to consider amending the LCFS regulation until the Scoping Plan update process has informed how the state's portfolio approach to climate mitigation may be best structured to deliver cost-effective, technologically feasible, and direct emissions reductions across various sources. CARB staff outlined the anticipated relationship between the 2022 Scoping Plan update and potential future LCFS amendments during the December 7, 2021, LCFS workshop. Specifically, because the 2022 Scoping Plan update will evaluate how California can achieve carbon neutrality by mid-century, including the types and role of low carbon fuels needed in the future, final Board member and public input on that update is likely to inform any eventual staff recommendations on potential amendments to the LCFS. Thus, our staff do not plan to formally propose regulatory changes to the LCFS until after the 2022 Scoping Plan update has been considered by the Board and after informal pre-rulemaking workshops on potential LCFS amendments. However, both the public meetings on the 2022 Scoping Plan update, and on concepts for potential changes to the LCFS as recently occurred, provide an opportunity for CARB staff and petitioners, in open public processes, to discuss the most beneficial role for biomethane in displacing fossil energy, and options to achieve the state's methane reduction targets for 2030. The public meetings of the Environmental Justice Advisory Committee, as well as the recommendations the committee will develop through that process, will provide an additional opportunity for conversation.

We recognize that consideration of LCFS amendments may be necessary to reflect direction from the Scoping Plan update and incorporate changes in conditions and policies that have occurred since the last major LCFS amendments in 2018. Therefore, similar to the public process on the 2017 Scoping Plan update and the 2018 LCFS amendments, CARB staff plan,

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[11] *See* LCFS public working meetings archive materials available here: *https://ww2.arb.ca.gov/resources/documents/lcfs-meetings-workshops-archive#2016*

[12] *See* 2018 LCFS amendments rulemaking materials available here: *https://ww2.arb.ca.gov/rulemaking/2018/low-carbon-fuel-standard-and-alternative-diesel-fuels-regulation-2018*

[13] A standardized regulatory impact analysis is required of any regulatory action "that will have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars ($50,000,000), as estimated by the agency." (Govt. Code Section 11342.548.)

throughout 2022, to host informal public workshops and meetings to discuss and consider potential changes to the LCFS program. Petitioners did participate in the initial LCFS public workshop on potential future changes to the LCFS program hosted by CARB staff on December 7, 2021, and submitted one[14] of more than 100 feedback letters received and currently under consideration following that workshop.[15] LCFS staff are currently evaluating that wide ranging public feedback, and working to schedule additional public meetings to continue that discussion.

Considering Senate Bill (SB) 1383 and the Need for Methane Reductions

SB 1383 (Stats. 2016, Ch. 395) codified the state's methane reduction milestones, which include the target of reducing statewide livestock manure methane emissions 40 percent below 2013 levels by 2030.[16] Methane is among the high global-warming potential gases with short atmospheric lifetimes we group under state law as "short-lived climate pollutants." In 2017, following a requirement in SB 1383, CARB approved a Short-Lived Climate Pollutant (or SLCP) Reduction Strategy,[17] which was designed as California's comprehensive plan for reducing SLCPs, including methane from dairies and other sources, and discussed the LCFS as one potential regulatory tool for promoting progress toward achieving SLCP reduction goals. In addition to directing CARB to potentially develop methane reduction regulations to achieve those targets, the same section of SB 1383 also directs CARB to "ensure" LCFS crediting for methane reductions.[18] The current LCFS provisions specifically authorizing the generation of LCFS credits for volumes of biomethane supplied as transportation fuel associated with captured methane from agricultural manure are responsive to that SB 1383 statutory direction. Beyond the petition's recommended exclusion of those fuels, to the extent that the petition recommends reform of those provisions to more effectively maximize benefits, and avoid potential harms, we welcome and appreciate petitioners ongoing engagement, and look forward to working with you in the consideration of any subsequent amendments to the LCFS.

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[14] Following the submittal of the petition, in addition to petitioners' January 7, 2022, comment following the December 7, 2021, workshop, petitioners submitted comments on December 14, 20, and 21, 2021, and January 24, 2022, regarding CARB certification of LCFS Tier 2 pathways posted for public comment. Those comments have been or will be addressed separately from this petition response as appropriate.

[15] December 7, 2021, LCFS public workshop materials available here: *https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-meetings-and-workshops*; public feedback received on the workshop, including letter from petitioners, available here: *https://www.arb.ca.gov/lispub/comm2/bccommlog.php?listname=lcfs-wkshp-dec21-ws*

[16] *Health & Safety Code, § 39730.7.*

[17] The 2017 SLCP Reduction Strategy and supporting documents, including the associated environmental analysis, are available here: *https://ww2.arb.ca.gov/resources/documents/slcp-strategy-final*

[18] Specifically, *Health & Safety Code, § 39730.7*(e) directs that CARB "shall ensure that projects developed before the implementation of [methane reduction] regulations [not yet developed or adopted now] receive [LCFS] credit for at least 10 years."

As supported by California's 2017 Scoping Plan, SB 1383, the 2018 LCFS rulemaking process, including its associated environmental analysis,[19] the current LCFS crediting regime for biomethane derived from animal manure is delivering the significant benefits it was designed to achieve. Specifically, the current LCFS crediting incentive for manure methane capture for transportation fuel use appears to be spurring the development of new digester projects. CARB staff estimates that those projects will significantly reduce methane emissions associated with the animal agriculture sector in California and beyond. Since the 2018 LCFS amendments came into effect, the number of operational digesters capturing methane from animal manure lagoons in California has nearly quadrupled, from approximately 20, to approximately 77 today.[20] CARB staff estimate that these new digesters, in addition to providing local odor and other air quality benefits,[21] will reduce methane emissions by approximately 75 percent[22] during the lifetimes of these projects. The current LCFS regulatory scheme in effect has supported replacement of diesel heavy duty vehicles with natural gas vehicles, which reduces GHG emissions and decreases criteria air pollutant emissions from transportation. Volumes of animal waste-derived biomethane reported as transportation fuel to the LCFS grew from less than 1.5 million therms, in 2018, to more than 20 million therms in 2020 (the latest full year for which reported volumes is available). Accordingly, potential future improvements to that part of the LCFS will be best addressed in the context of a broader effort to strengthen the regulation as informed by the state's updated overall climate change strategy. We recognize the concerns expressed in your petition about facility consolidation issues, and potential associated environmental impacts, and look forward to reviewing additional data and continuing discussion throughout the workshop and regulatory processes.

Determination and Conclusion

Therefore, after careful consideration of your petition, the relevant law, and the current context of ongoing development of the next AB 32 climate change Scoping Plan and anticipated subsequent regulatory activity, I have reached a decision on your petition, pursuant to Government Code section 11340.7.[23] The Code provides that CARB "may grant

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[19] *Final Environmental Analysis for Amendments to the Low Carbon Fuel Standard and the Alternative Diesel Fuels Regulation*, September 17, 2018.
[20] U.S. Environmental Protection Agency, Livestock Anaerobic Digester Database, available here: *https://www.epa.gov/agstar/livestock-anaerobic-digester-database*
[21] See, for example, non-GHG air quality benefit information reported associated with digester projects supported by the Dairy Digester Research and Development Program (DDRDP) administered by the California Department of Food and Agriculture, available on the *California Climate Investments Project Map*.
[22] According to *California's Greenhouse Gas Inventory*, methane emissions from an anaerobic lagoon is estimated at 8.3 tons CO2e per dairy cow per year, whereas methane emissions from an anaerobic digester is estimated at 2.06 tons CO2e per dairy cow per year.
[23] The Board may delegate any duty it deems appropriate to its Executive Officer (Health and Safety Code section 39515(a)). The Board is conclusively presumed to have delegated any of its powers to the Executive Officer unless it has expressly reserved that power to itself (Health and Safety Code section 39516). The Board has not reserved the power to act on rulemaking petitions and it is, therefore, appropriate for me to act on this petition pursuant to my delegated authority.

or deny the petition in part, and may grant any other relief or take any other action it may determine to be warranted by the petition."[24] I am denying your petition in part, and granting other relief in part.[25] Specifically, I am:

(1) Denying your petition in part by declining to amend the LCFS Regulation at this time in the manners suggested.

(2) Granting other relief by affirming that CARB will continue to engage with petitioners on the programmatic and environmental justice and environmental integrity concerns raised in the petition through the ongoing AB 32 Climate Change Scoping Plan update process and upcoming informal workshops on LCFS throughout 2022, both of which will inform any future LCFS amendments. The proposed amendments will be fully vetted in a public process when we launch the formal rulemaking process in early 2023. Throughout this process CARB will continue to focus on improving air quality and health in the state's most impacted communities, ensure progress is made in achieving state and federal air quality standards, and reduce GHG emissions from all sources. CARB is committed to continue to encourage the reduction of emissions from dairy and swine farms.

The record upon which this decision is based includes the petition and its exhibits, this letter, the materials referenced herein, and its attachments.

In accordance with Government Code section 11340.7, subdivision (d), a copy of this letter is being transmitted to the Office of Administrative Law for publication in the California Regulatory Notice Register. The agency contact person in this matter is Gabriel Monroe, Senior Attorney, available at (916) 324-2132 or Gabriel.Monroe@arb.ca.gov. Interested parties may obtain a copy of the petition upon request to Chris Hopkins, available at (279) 208-7347 or Chris.Hopkins@arb.ca.gov. Upon request, physical copies would be obtained from 1001 I Street, Sacramento, California, 95814.

Sincerely,

Richard W. Corey
Executive Officer
California Air Resources Board

cc: (via email only)

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[24] Govt. Code, § 11340.7(b).

[25] Government Code 11340.7 provides that an agency addressing a petition shall "identify the agency, the party submitting the petition, the provisions of the California Code of Regulations requested to be affected, reference to authority to take the action requested, the reasons supporting the agency determination, an agency contact person, and the right of interested persons to obtain a copy of the petition from the agency." This response fulfills those requirements.

cc: Phoebe Seaton, Leadership Counsel for Justice & Accountability
Tom Frantz, Association of Irritated Residents
Tarah Heinzen, Food & Water Watch
Tyler Lobdell, Food & Water Watch
Cristina Stella, Animal Legal Defense Fund
Christine Ball-Blakely, Animal Legal Defense Fund
Liane M. Randolph, CARB Chair
Honorable Board Members
Rajinder Sahota, CARB Deputy Executive Officer
Chanell Fletcher, CARB Deputy Executive Officer
Ellen M. Peter, CARB Chief Counsel

Attach. 5

Sent via email

January 26, 2022

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Phoebe Seaton
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Brent Newell
Public Justice
bnewell@publicjustice.net

Re: Requests to Deny or Delay Consideration of Low Carbon Fuel Standard (LCFS) Pathway Certifications

Dear Mr. Lobdell, Ms. Seaton, Mr. Frantz, Ms. Ball-Blakely, and Mr. Newell,

Thank you for the comment letters[1] you submitted in December 2021 and January 2022 requesting that the California Air Resources Board (CARB) deny certification of fuel pathway applications under the Low Carbon Fuel Standard (LCFS) regulation.[2]

Your comment letters reference and attach your "Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program" (Petition), which you all first submitted to CARB on October 27, 2021. We appreciate that petitioners agreed to toll the deadline for CARB's response to the

[1] Specifically, this letter is responsive to the similar comment letters petitioners submitted on LCFS Tier 2 pathway application numbers *B0220*, *B0207*, *B0218,* and *BO280,* as well as petitioners' *January 7, 2022 LCFS workshop feedback letter*. All LCFS Tier 2 pathway public postings, including pathway application information, public comments, and responses from LCFS pathway certification applicants are available *here*.

[2] The Low Carbon Fuel Standard regulation appears at sections 95480 to 95503 of title 17, California Code of Regulations (CCR). For concision, most citations to sections of the LCFS regulation in this letter refer specifically to the section numbers within this range, omitting broader reference to title 17, CCR, where these sections are published.

Petition to January 28, 2022, while we took opportunities to discuss the petition with petitioners to better understand the concerns as well as the availability of supporting documentation. I write to respond briefly to petitioners' pathway comment letters with contextual clarification that I hope might be helpful. This response letter addresses only the petitioners' letters regarding CARB certification of LCFS Tier 2 pathways, and not petitioners' petition for rulemaking, which we have responded to according to the applicable process.

The Petition requests CARB begin a rulemaking process to amend the LCFS regulation. Consistent with the California Administrative Procedure Act, the Petition is not a proper legal mechanism to stop implementing the current version of the LCFS regulation. The current LCFS regulations were adopted through the robust public rulemaking process required by law, and the law requires a similar process for any amendments to ensure all members of the public have an opportunity to engage with CARB prior to any adoption. Accordingly, under current law,[3] CARB must continue routine implementation of the aspects of the LCFS regulation that petitioners asked CARB to amend.

Nevertheless, following the initial October 2021 submission of the Petition, you have requested several times, both verbally in meetings with CARB staff and management and in writing in these public comments on fuel pathway certifications, that CARB agree to cease animal manure biomethane fuel pathway certifications until the Petition's requested amendments are finalized. These pathway certifications are routine implementation of aspects of the current LCFS regulation that the petitioners also request that CARB consider initiating a rulemaking process to amend. While we appreciate petitioners' engagement on both the Petition itself and on ongoing LCFS implementation, petitioners' supplemental request is essentially a request for CARB to grant their Petition in effect while it is still under consideration, which would bypass the legally required open public regulatory amendment process that the Petition requests be initiated.

Thank you again for your comments and ongoing interest in this aspect of the LCFS. We look forward to continuing to work with petitioners to improve the LCFS in the future.

Sincerely,

Gabriel Monroe, Senior Attorney
Legal Office, California Air Resources Board

cc: (via email only)

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[3] *Government Code § 11340.5*(a) outlines this elemental principal of administrative law: "No state agency shall issue, utilize, enforce, or attempt to enforce any guideline, criterion, bulletin, manual, instruction, order, standard of general application, or other rule, which is a regulation as defined in Section 11342.600, unless the guideline, criterion, bulletin, manual, instruction, order, standard of general application, or other rule has been adopted as a regulation and filed with the Secretary of State pursuant to this chapter."

Liane M. Randolph, CARB Chair
Richard W. Corey, CARB Executive Officer
Rajinder Sahota, CARB Deputy Executive Officer
Ellen M. Peter, CARB Chief Counsel

Attach. 6

Union of Concerned Scientists

To: Cheryl Laskowski

From: Jeremy Martin

Date: January 6, 2022

Subject: Manure biomethane analysis

As we mentioned in our 2021 feedback on the Scoping Plan, we are becoming increasingly concerned that the subsidies for manure-based biomethane arising from the LCFS are excessive and likely subsiding the largest confined animal feeding operation (CAFO) dairies, contributing to industry consolidation and putting dairies that use other manure methane strategies at a competitive disadvantage. We urge CARB to revise the lifecycle accounting or otherwise adjust the program to avoid these bad outcomes and ensure that the LCFS is an effective tool for transportation decarbonization without contributing to problems in other sectors of the economy.

We recognize that the capture and productive use of waste biomethane generated by anaerobic digestion (AD) from manure lagoons is a useful mechanism to mitigate methane pollution and can also replace a small amount of fossil methane use in energy and industrial applications. Over the last several years, we have heard conflicting arguments about whether the support from the LCFS was necessary to offset the costs of implementing AD or a huge windfall that was distorting the economics of dairies with harmful consequences. An analysis by Professor Aaron Smith at UC Davis suggested that the subsidy associated with LCFS credits for dairy biomethane was an order of magnitude larger than the cost to run and maintain a digester, and indeed that this value per cow is half as large as the value of the milk[1]. If this is true, it raises methodological and policy questions about the treatment of the manure biomethane under the LCFS.

To get a better handle on the issue, we commissioned Professor Kevin Fingerman and Amin Younes of Humboldt State University and the Schatz Energy Research Center to do some preliminary analysis of the issue, which we attach here. Their findings confirm what Professor's Smith's earlier work suggested, that the value of LCFS credits for a large, confined animal feeding operation (CAFO) dairy vastly exceed the cost of recovering the biomethane. This new analysis is not exhaustive, as it does not conduct a full market analysis of how much of the subsidy value of the LCFS is captured by the biomethane producer, versus what is captured by the biomethane user or other parties to the transaction. However, we believe the analysis suggests a high risk of adverse outcomes that could undermine the goals of the LCFS and broader California policy and warrant further scrutiny at the soonest possible opportunity.

Methodologically, the extremely large negative carbon intensity (CI) values for manure biomethane are the result of several assumptions and judgements made by CARB in the life-cycle analysis that bear reconsideration. In particular, CARB should revisit the assumption that the methane from manure lagoons is purely a waste product with no value that would be emitted into the atmosphere absent the LCFS support for use as a transportation fuel. In light of the large subsidies derived from the LCFS, nearly as large as the value of the milk produced at a large dairy, it is naïve to assume the policy will have no

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[1] Aaron Smith. 2021. "What's Worth More: A Cow's Milk or its Poop?" asmith.ucdavis.edu/news/cow-power-rising

impact on the economics of the dairy industry going forward. There are any number of alternative lifecycle treatments that may be appropriate in the development of the CI score, for example treating biomethane as a coproduct rather than a waste. However, it might also be appropriate to address this concern through other means, such as guardrails within the LCFS policy to avoid negative spillover effects in agriculture. For example, it may be appropriate to set a floor of zero on the CI scores for fuels absent compelling documentation of permanent carbon sequestration. Avoided methane emissions could potentially still be sold on carbon offset markets, but their inclusion in the valuable LCFS program is distorting both the market for feedstocks and the market for carbon mitigation. Because the LCFS places an especially high effective carbon price on emissions associated with transportation fuels, it creates an incentive for only and specifically any emission avoidance that can be diverted to fuels – whether or not that's the lowest cost abatement and whether or not fuel is the most efficient pathway for that feedstock.

Aside from methodological concerns, we question whether the current LCFS approach to manure methane is good policy. The LCFS is structured to require producers of polluting transportation fuels to bear the costs of mitigating transportation fuel pollution. However, in the case of the manure biomethane, the majority of the climate pollution at stake is methane from manure, and the fossil methane displacement in the transportation fuel market is a relatively small contribution. Thus, in this instance the largest polluter is the one receiving a large subsidy.

The lifecycle basis of the LCFS is supposed to ensure that support for low carbon fuels is based on a comprehensive assessment of their climate benefits. However, in this instance, this structure is functioning as poorly designed offset program with transportation fuel users paying an extremely high price for manure methane mitigation. This is not good transportation fuel policy or good agricultural methane mitigation policy.

From a transportation policy perspective, a vehicle operating on manure biomethane with a CI score of negative several hundred g CO_2e/MJ appears by the logic of the current accounting to fully offset the CO_2 emissions from several internal engine vehicles running on petroleum fuels. But is a fleet of three diesel trucks and one CNG truck powered with manure biomethane really equivalent to a fleet of four electric trucks powered with solar energy? The extravagant credits awarded to manure biomethane for methane destruction by the current lifecycle analysis come at the expense of support for other low carbon fuels and divert the focus of the LCFS to purposes outside of transportation. The LCFS should work in concert with other policies to minimize the use of combustion fuels in transportation, while also minimizing the supply chain emissions from all fuels. By awarding the most favorable CI score to a combustion technology, the manure biomethane pathway sends a confusing and contradictory policy signal.

From a methane mitigation perspective, there is a reasonable case for public support for strategies that reduce methane pollution, including overcoming the cost barriers to AD. However, this support should be in proportion to the relevant cost barriers and these costs should ultimately be internalized within the food supply chain. While the low rate of AD adoption in the early years of the LCFS policy may have initially justified an assumption of unmanaged methane pollution in the counterfactual scenario, this treatment is not justified indefinitely. AD operators will quickly earn more in credits than they spent on AD installation, especially given additional grants available for these projects. Maintaining indefinitely a counterfactual scenario that assumes no methane control has the effect of paying AD operators their costs many times over to continue to operate equipment that is already paid for. Reducing the level of support for manure methane by revising the counterfactual assumption would still provide a reasonable level of support for AD based on avoided CO2 emissions without a subsidy so large that it risks distorting agricultural markets.

We do not believe it is wise to make the generation of waste methane a substantial ongoing source of profit for CAFO dairies. First, the main climate benefit of AD is reduced agricultural methane pollution, with displaced fossil methane a secondary benefit. But the LCFS incentive puts other methane mitigation strategies at a disadvantage if they do not simultaneously generate transportation fuel. Some of these other strategies, such as alternative manure management, have other significant co-benefits outside the transportation sector. But dairies using alternative manure management strategies could be priced out of the milk market because competitors receive large subsidies for methane destruction associated with transportation fuel production that are not available to diaries adopting methane avoidance strategies that do not result in fuel production. Also, the analysis below suggests that even among facilities with AD systems, smaller facilities may be at a significant disadvantage compared to the largest CAFOs. The largest CAFOs are associated with many ecological and environmental justice problems, and subsidizing their operations is likely to exacerbate these harms and contribute to further industry consolidation with adverse consequences for overall GHG emissions from California's natural and working lands.

It is important to ensure that policies influencing the food system support just and equitable outcomes, including reductions of both global and local pollution, and that transportation fuel policies do not create distortionary subsidies with negative unintended consequences in the food system. We recognize that this is a complicated issue that deserves careful consideration and that the analysis included here is preliminary and incomplete. We urge you to reconsider in the next rulemaking how best to structure the LCFS manure biomethane pathways to ensure they support agricultural methane reductions in an effective and equitable manner without contributing to harmful outcomes outside the transportation sector.

Regards,

Jeremy Martin

Director of Fuels Policy, Senior Scientist
Clean Transportation Program
Union of Concerned Scientists

Attach. 7

Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard

Version 1.2, September 2021

Prepared by:

Amin Younes and Kevin Fingerman, PhD

Prepared For:

Union of Concerned Scientists, Washington DC

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CONTENTS

1. Introduction and Purpose

This report documents a study of the subsidies available to dairy farms from selling low-carbon manure-based bioelectricity under California's Low Carbon Fuel Standard (LCFS). It investigates the potential for this revenue stream to distort dairy market economics in a way that may favor larger cattle-raising operations. Farms are assumed to build covered manure lagoon anaerobic digesters and to generate electricity onsite from the resulting methane (in the form of biogas, a substance about half as methane rich as natural gas), although farms could, and some do, instead upgrade this biogas to renewable natural gas for pipeline injection (see Appendix A).

California's Low Carbon Fuel Standard is a key piece of climate policy aimed at decarbonization of the transportation sector by enabling low-carbon petroleum alternatives [1]. Under the LCFS, a generator of low-CI (carbon intensity) electricity can supply it to the California grid and use a book-and-claim system to generate LCFS credits or allow a third party to generate credits on their behalf [2, Sec. 95488.8(i)], [3], [4]. This electricity must be used as a transport fuel within three calendar quarters of being supplied to the grid, but need not be physically traceable between source and end-use [2, Sec. 95488.8(i)(A)]. This third party may, for example, contract with electric vehicle (EV) fleets to provide electricity needed for charging and use the revenue generated from credits for offsetting electricity costs, purchasing electric vehicles, and "improving dairy economics" [3, p. 3]. The generator must also submit a Tier 2 fuel pathway application including a life-cycle assessment (LCA) showing how much carbon is emitted in the use case relative to a base case for that resource (i.e., manure that is anaerobically decomposing in lagoons). This process allows dairies to generate revenue from the LCFS, creating a potentially valuable subsidy to these farms.

There are currently 42 Tier 2 dairy pathways approved under the LCFS, of which ten deliver electricity and 26 produce compressed natural gas (CNG) which is piped to usage locations within California (the remaining six pathways produce gaseous or liquid hydrogen). Because, as shown in Appendix A, the electricity pathways have the potential for higher profit margins, we focus on these pathways, which currently have certified carbon intensities between -109 gCO_2e/MJ and -762 gCO_2e/MJ [5], though a similar potential exists for CNG used in trucks. The specific details of all certified LCFS pathways are confidential, but negative emissions associated with electricity or natural gas derived from manure is generally attributable to capture and combustion of methane from manure lagoons, which is therefore credited with the avoided open release of that methane [6].

It is worth taking a moment to discuss the negative emissions associated with destruction of methane more broadly. At present, manure is responsible for ¼ of methane emissions in California [7] and methane is responsible for 9% of California's global warming from greenhouse gases (taking into account relative global warming potentials) [8]. The alleged negative emissions in these pathways are due to significant release of methane during storage of manure in lagoons or ponds where it anaerobically decomposes [9]. Methane (CH_4) has a high global warming potential — 25 times higher than carbon dioxide (CO_2) over a 100-year timeframe [10] — so simply capturing and burning methane (i.e., flaring) is an effective way to reduce greenhouse gas emissions relative to its free release. So too are alternative manure management methods such as spreading manure on fields where it *aerobically* decomposes and releases a significantly smaller amount of methane. It is likely that there is some correlation between the size of a dairy operation and the probability that the manure produced is stored in ponds rather than naturally dispersed across rangeland, however, no data was identified by the authors supporting or refuting this claim. There does not appear to be a significant correlation between dairy size and probability of confinement, with 80% to 85% of animals on farms larger than 19 head confined, regardless of farm size (farms smaller than 19 cows were assumed not to confine animals in the study) [11].

In 2017, California was home to some 1,700 dairies with an average size of 1,100 cows per dairy. While the total number of dairy cows in the state rose between 1997 and 2017, the number of farms decreased by 40%, with the average number of animals per dairy doubling, as shown in Figure 1. This consolidation trend well predates the generation of LCFS credits from manure, but the significant value of LCFS credits combined with the economies of scale present in biogas generation and combustion [12] could serve to further distort the market economics in further favor of larger cattle-raising operations.

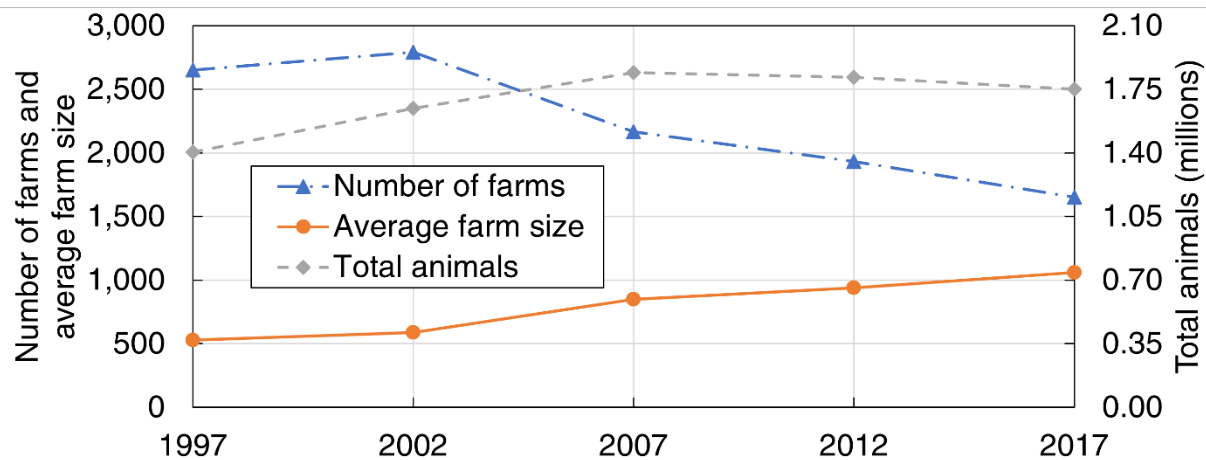

Figure 1. Change in dairy farm quantity and size over two decades [13].

We evaluated the economics of energy generation on dairy farms from the scale of a single cow to 15,000 cows to determine how the profit derived from LCFS credits varies with changing production costs associated with economies of scale. We compared the profit available to the dairy farm from sale of manure-based electricity under the LCFS to the profit derived from the dairy itself and assessed the lifecycle emissions that could be attributed to the manure-based transport fuel using value-based coproduct allocation and revenue-based coproduct allocation.

2. METHODS

We began by assessing the value derived from a unit of bioelectricity under the LCFS at several levels of certified CI. Next, we calculated the cost of production and resulting profit as a function of farm size. We then compared these to the dairy's milk production revenue and profit. Finally, we evaluated the impact to the certified CI that would result from attributing some of the dairy production emissions to the energy product via two methods of coproduct allocation.[2]

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[2] In life cycle carbon accounting, when more than one product is created from a single feedstock, some of the emissions associated with the feedstock must be attributed to each product. This can be done by any number of factors, including their relative masses, energy contents, or market values, and is called coproduct allocation. Coproduct allocation is generally not performed when one of the "products" is considered to be a waste, which is how manure is treated at present. We investigate the result if the

2.1. Biolectricity Revenue

The revenue bioelectricity can receive from the LCFS depends on two factors: The value of credits ($/MT), and the emissions displaced by the low-carbon fuel (MT/MJ).

Average credit price rose from $160 in 2018, to $192 in 2019, to $199 in 2020. In the first few months of 2021 (Jan-May), prices have varied between $190 and $198 per credit [14]. We use a credit value of $195/MT, which is the weighted average price in 2021 to date and quite close to recent monthly and annual average prices.

The displaced emissions are calculated from three factors: The carbon intensity (CI) of the bioelectricity (gCO_2e/MJ), the CI of the referent, the 2021 gasoline benchmark, and the energy economy ratio (EER) of the vehicle drivetrain relative to a gasoline vehicle.[3] Displaced emissions were calculated as follows (adapted from [2, Sec. 95486.1]):

$$D = EER \cdot CI_{Referent} - CI_{Bioelectricity}$$

Where:

- EER = 3.4 for light-duty electric vehicle use [2, Sec. 95486.1]. Heavy-duty electric vehicles have higher EER, up to 5.0, and would thus displace more carbon per unit of bioelectricity, but claiming use in these vehicles is likely to be competitive, and presents no outsized opportunity to manure-based bioelectricity, so we use the EER of the far more common light-duty electric vehicles.
- $CI_{Referent}$ = 91 gCO_2e/MJ [2, Sec. 95484], the 2021 gasoline benchmark.
- We consider three values of $CI_{Bioelectricity}$, as described below.

First, we evaluated LCFS revenue for dairies with a certified CI equal to the average[4] of currently approved manure-based bioelectricity pathways: -461 gCO_2e/MJ [5]. Second, we used the largest magnitude (i.e., most negative) value of currently approved manure-based bioelectricity pathways [5], which is -762 gCO_2e/MJ. This value is substantially lower than the average value; however, since life-

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status of manure as a waste were changed, and we use two methods: The relative revenue associated with manure-based electricity versus dairy, and the relative profits of the two.

[3] The energy economy ratio reflects the fact that different types of vehicles consume their fuels in different ways and at significantly different efficiencies. In a gasoline or CNG vehicle the fuel is combusted, which is a relatively inefficient process compared to conversion of electricity to mechanical motion in a battery electric vehicle (BEV). As a result, a BEV can travel 3.4 times as many miles compared to a gasoline vehicle per unit of energy consumed. By applying an EER to the carbon intensity score, LCFS comes closer to crediting carbon savings per mile travelled rather than simply per unit of energy delivered.

[4] This number is the simple average among the approved pathways. Using the most recent report [15] of credits and generation from non-grid-average and non-zero-CI electricity, which appears to align with the dairy manure pathways plus a single organic waste pathway among approved LCFS pathways [5], and assuming an EER of 3.4 and 2020 reference CI for gasoline yields a weighted average CI of -487, modestly less (5%) than the simple average.

cycle analysis details are fully redacted, it is uncertain where this variability comes from. Finally, we used 0 gCO_2e/MJ, a notional alternative. These resulted in the following three estimates for displaced emissions, *D,* and LCFS credit revenue (per unit of electricity produced), provided in Table 1. For context, the present federal production tax credit available to electricity generated from wind power is $25/MWh, or $0.007/MJ, nearly an order of magnitude less than the subsidy available to zero-CI bioelectricity [16] (though it should be noted that the former is not assumed to be a transport fuel).

Table 1. The displaced emissions per MJ and resulting value derived from credit sales under the LCFS in three emissions scenarios with recent credit pricing of $195/MT.

Estimate	CI (gCO_2e/MJ)	*D* (gCO_2e/MJ)	Revenue ($/MJ)
Highest CI (for reference)	-109	418	$0.082
Average CI	-461	770	$0.150
Most-negative CI	-762	1,071	$0.209
Zero CI (notional)	0	309	$0.060

The above CIs are "adjusted" per California Air Resources Board (CARB) guidance in order "to reasonably limit the LCFS incentive for low-efficiency pathways relative to higher efficiency ones" [17, p. 3]. Without this adjustment, lower efficiency pathways would produce less electricity, but with a lower (i.e., more negative) CI because the total avoided methane emissions remain constant. Therefore, CARB requires biogas to electricity pathways to discount calculated carbon intensities by the engine efficiency relative to a benchmark of 50% ("a reasonable efficiency benchmark based on the average efficiency of NG-derived electricity at California power plants and best available technologies for electricity production"[5]) [17, pp. 3–4]. The net effect of this CI adjustment is that less efficient pathways produce less electricity at the same CI as more efficient pathways and are thus incentivized to use higher efficiency generators to generate more credits. Therefore, we modeled CI as independent of engine efficiency in the below analysis.

2.2. Bioelectricity Production Cost

We built cost and biogas productivity estimates for farms up to 15,000 cows assuming they build covered lagoon digesters and onsite generators. These facilities show significant economy of scale, enabling much higher profits for larger operations. In principle, these same profits are available to groups of smaller operations which aggregate their manure, although aggregation and transport costs would need to be added in this case. We then calculated total annual costs by annualizing digester and engine capital costs and adding this to the annual operational expenses for engines [19] and digesters [12], respectively. From the annual costs, we subtracted the revenue from electricity sales, assuming electricity is sold at $79 /MWh,[6] to determine the annual net cost of building and running the anaerobic

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5 The 2019 weighted average thermal efficiency of the California natural gas fleet was 44.2%, largely driven by the efficiency of combined-cycle natural gas plants, averaging 46.6%. Internal combustion engines, such as those that would be used in onsite generation, have a notably lower efficiency, falling into a category ("miscellaneous") with a 2019 average thermal efficiency of 36.6% [18].

6 We used the generation-weighted average power price for the 51 California power plants in the 2019 EIA Power Plant Operations dataset [20] which report using at least 50% qualifying biofuels as feedstock.

digester and onsite electricity generation operation. We then calculated the net electricity production cost (before LCFS credit revenue) per MJ of electricity, by dividing this total cost by the annual electricity production for each farm size. Additional details are provided in Appendix B.

3. Results

Based on the assumptions of this model, farms with 94 or more cows could economically build and operate anaerobic digesters with onsite electricity generation, assuming they achieve the most-negative CI currently recorded within the CARB database [5]. With the more moderate assumption of the average CI within the database, farms would have to be modestly larger, 150 cows, before building a digester would be profitable. In the case of zero-CI manure-based electricity, farms of 580 cows or more could viably build and operate digesters with onsite generation.

For extremely large farms, above 14,000 head of cattle, the net-cost of production falls below one cent per MJ as depicted in Figure 2. Over this range, profits are nearly equal to the value of the LCFS credits, since the net-cost of production is insignificant by comparison. Fifteen-thousand-cow farms would generate a profit of $0.05, $0.14, or $0.20 per MJ produced in the zero-CI, average-CI, and most-negative-CI cases, respectively.

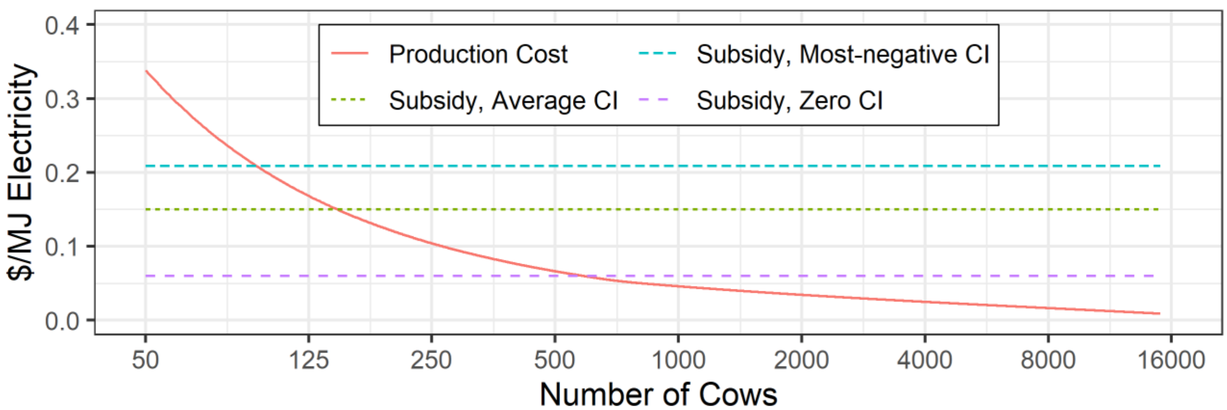

Figure 2. Net production cost (total cost minus electricity revenue) and LCFS credit revenues (i.e., subsidy) by farm size. Note that the x-axis is logarithmic.

There are two important sources of potential error to consider in this analysis: First, smaller operations may have additional unaccounted for costs of manure aggregation, especially if these operations do not currently confine their cattle or aggregate their manure in lagoons (in fact, farms which do not aggregate manure in lagoons would not be able to receive LCFS credits, as discussed earlier). Second, our engine model is built from data for systems 100-kW and larger, and we do not extrapolate outside this range. This results in farms under 700 head of cattle having an oversized generation unit, which

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This yielded a wholesale price of bioelectricity of $78.59/MWh (SD: $34.24). This is a relatively high price for wholesale power, but it is reflective of current market conditions. In part, these high prices may reflect the value of bundled Renewable Energy Credits (RECs) generated under CA's Renewable Portfolio Standard as well as other price supports such as Feed-in Tariffs or Production Tax Credits that are available in some jurisdictions.

could lead to an overestimate of their costs. Smaller engines have been tested [21], [22]; however, they may not be grid compatible due to instabilities [23].

3.1. Subsidy Value Per Gallon of Milk Produced

To add additional context to these results, we brought milk production into the picture by calculating the electricity profit (i.e., LCFS subsidy - production cost in Figure 2) per gallon of milk. We assumed that each dairy cow produces 2,720 gallons (23,500 lbs.) of milk per year [24].

The profit derived from LCFS credits reaches \$0.14 and \$0.39, and \$0.55 per gallon of milk for the largest studied farm size (15,000 cows), across the three CI cases (0, -461, -762 gCO_2e/MJ), as depicted in Figure 3. A 2,000-cow dairy would derive somewhat lower subsidies, and a 100-cow dairy little to no profit, as shown in Table 2.

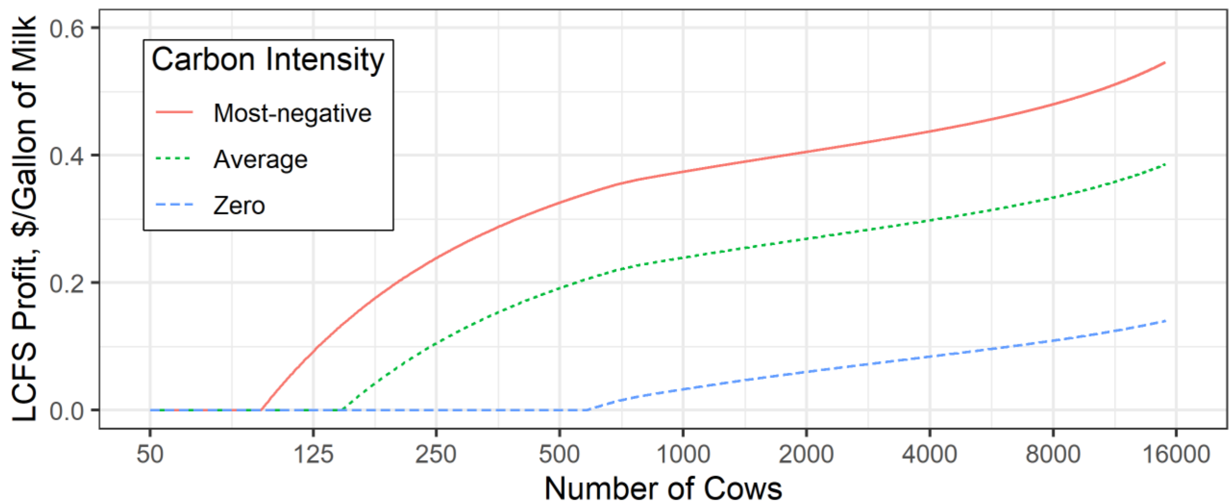

Figure 3. LCFS profit to dairies per gallon of milk under three different CI conditions. Note that the x-axis is logarithmic. The point of departure from \$0/gallon indicates the farm size at which electricity generation becomes profitable at a given CI.

Table 2. LCFS credit profit per gallon of milk across farm sizes and conditions of bioelectricity CI.

	LCF Profit, \$/Gallon of Milk		
Number of Cows	Most-negative CI (-762 gCO2e/MJ)	Average CI (-461 gCO2e/MJ)	Zero CI
100	\$0.02	\$0.00	\$0.00
500	\$0.33	\$0.19	\$0.00
1,000	\$0.37	\$0.24	\$0.03
2,000	\$0.41	\$0.27	\$0.06
10,000	\$0.50	\$0.35	\$0.12
15,000	\$0.55	\$0.39	\$0.14

We can compare the profit generated under the LCFS to the profit from milk sales. To do so, we assumed the profit from the milk to be $4.30/cwt, 7 an estimated profit margin of 25% [25] times the wholesale price of $17.20/cwt.8 [27], [28] This is equivalent to $1.48 wholesale per gallon, or $0.37 of profit per gallon. The results of this comparison are depicted in Figure 4, which shows the profit derived from the LCFS as a fraction of total profit (LCFS profit + dairy sales profit). In the case where the CI of manure-based bioelectricity is assumed to be zero, the profit which dairies accrue from the LCFS only exceeds 25% of their total profit for large farms—11,000 head and larger. Conversely, in the other two cases, farms over 280 head derive over 25% their profit from LCFS credits.

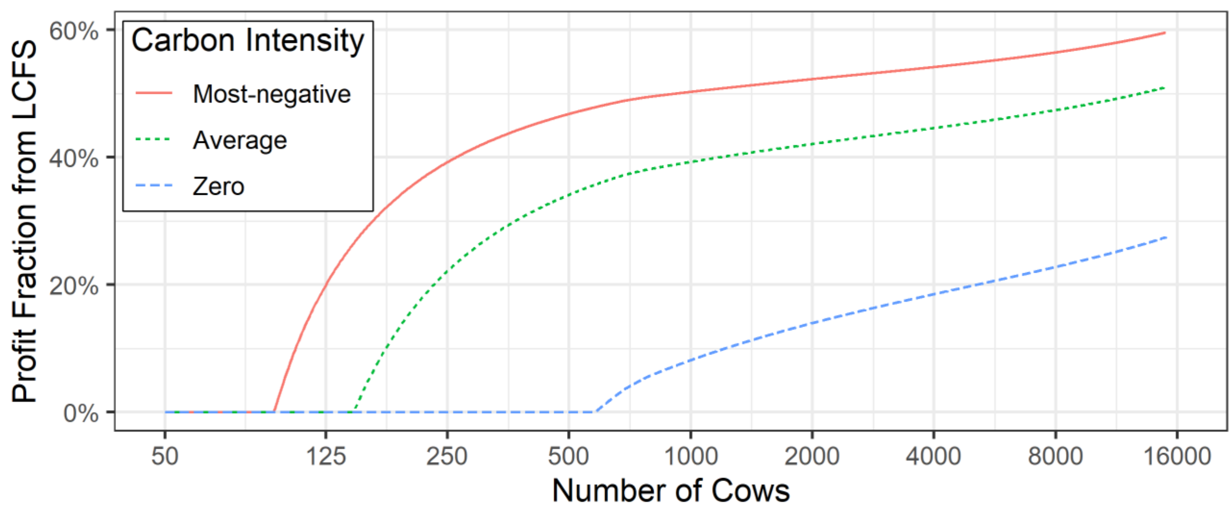

Figure 4. Fraction of profit attributable to LCFS credits as a function of dairy size and the CI of manure-based bioelectricity. Note that the x-axis is logarithmic. The point of departure from 0% indicates the farm size at which electricity generation becomes profitable at an assumed CI.

If, instead of considering the estimated profit fraction from LCFS credit revenue, we observe the calculated fraction of income from electricity (inclusive of electricity sales and LCFS credit sales) compared to the income from milk (i.e., $1.48/gallon), the result is far less dependent upon the scale of the facility,9 but remains significantly dependent on the certified CI of the electricity. For the average CI case, the revenue fraction from electricity sales ranges from 21% to 24% of the total revenue, and for the most-negative CI case it varies from 26% to 30%. In both cases, smaller farms derive slightly less of their revenue from electricity.

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7 Wholesale milk prices use the units of hundredweight, which are abbreviated as 'cwt' and equal to 100 pounds.

8 Based on historic data [26] we assume that 30% of milk is class I, 40% is class III, and the remainder is split evenly between class II and class IV. The most recent prices for class I-IV respectively are: $18.29/cwt [27] $15.56/cwt, $17.67/cwt, and $15.42/cwt [28]. This leads to a weighted-average price of $17.20/cwt.

9 Since the economy of scale of electricity production is no longer a factor, the only impact is the ratio of milk sales to electricity sales which decreases slightly at larger scale due to the higher efficiency engines used in our model.

3.2. Coproduct Allocation

Manure is, at present, considered to be a waste product. Therefore, none of the emissions from milk production are allocated to manure or manure-based bioelectricity production. However, as was shown above, a significant fraction of the revenue of a dairy farm with anaerobic digesters and a significant fraction of the profit from medium-to-large dairies with anaerobic digesters could come from manure that has been concentrated into anaerobic lagoons such that methane is created. The principles of lifecycle assessment suggest that some of the emissions associated with raising dairy cattle should therefore be attributed to this "valuable" coproduct.

Thoma et al. [29] estimate a life-cycle GHG emission of 2.05 kg-CO_2e per kg of milk consumed. Downscaling this to account for the 30% lost before consumption and the 24% of emissions from manure management — which will be largely eliminated via the biogas-to-electricity pathway — results in an estimate of 1.09 kgCO_2e per kg of milk produced.

Dividing the emissions associated with milk production by the quantity of electricity produced by the same farm allows comparison between the scale of methane emissions avoided by capturing and combusting biogas and those stemming from dairy production. As depicted in Figure 5, the emissions from cattle raising (excluding those associated with manure) are significantly larger than those avoided by capturing and combusting biogas (and linearly decrease as farm size increases due entirely to the higher efficiency of larger engines in our model). The scale of these emissions is 2-2.5 times the magnitude of displaced emissions with the most-negative CI and 3.5-4 times the magnitude of those using average CI, meaning that attribution of a portion of these emissions to biogas-based electricity will significantly impact its CI.

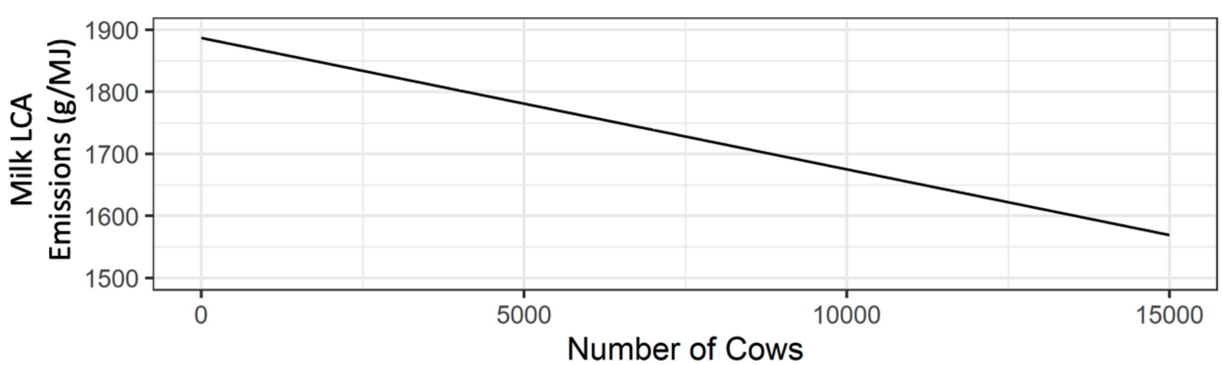

Figure 5. Variation in Milk LCA emissions per MJ of electricity with farm size.

To explore the effect of this allocation on pathway CIs, we attributed a portion of the emissions from dairy production to electricity based upon either the relative revenue or the relative profit. This caused the CI of the electricity to increase (i.e., move towards zero), resulting in lower displaced emissions and lower LCFS revenue. Because the revenue or profit from the electricity would then be lower, thereby changing the relative fractions of profit or revenue, we iterated the CI calculation until it converged to a stable result. This result is summarized in Table 3 for both revenue-based allocation and profit-based allocation methods, and graphically in Figure 6 for profit-based allocation (revenue-based allocation is not shown graphically because the variation is small across notional farm sizes).

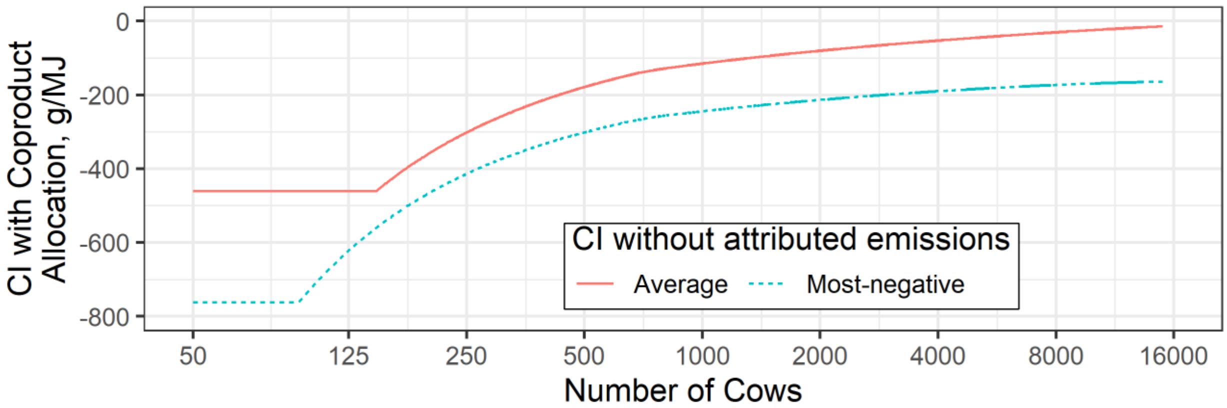

Figure 6. Updated CIs using coproduct allocation based upon relative profit.

Table 3. Updated CIs using coproduct allocation based upon relative profit and from relative revenue comparison.

Number of Cows	Using Profit-Based Allocation[10] Average CI (-461 gCO_2e/MJ)	Using Profit-Based Allocation[10] Most negative CI (-762 gCO_2e/MJ)	Using Revenue-Based Allocation[10] Average CI (-461 gCO_2e/MJ)	Using Revenue-Based Allocation[10] Most negative CI (-762 gCO_2e/MJ)
100	-461	-724	-175	-393
500	-178	-301	-175	-393
1,000	-115	-244	-175	-393
2,000	-80	-213	-176	-393
10,000	-24	-169	-179	-399
15,000	-14	-164	-181	-403

For small farms, little to no profit is generated from the LCFS, and emissions would be attributed entirely to milk production; however, for larger farm sizes, profit margins on electricity sales quickly outpace profit margins on wholesale dairy, and more emissions are therefore attributable to bioelectricity, bringing the CIs of dairy-derived electricity towards zero. Revenue allocation leads to similar CIs across farm sizes, with the increased ratio of electrical output to milk output (due to increased engine efficiency) leading to slightly lower CIs for larger farms because the milk LCA emissions are spread across more MJ of electricity.

After performing the coproduct allocation, we revisit the enabled LCFS credit profit per gallon of dairy as a function of the original CI and allocation method in Figure 7. LCFS profit generally falls between the

10 Because the certified CI is representative of a physical phenomenon, namely avoided emissions due to combustion of biogas from manure via the bioelectricity pathway, the new CI is dependent upon the original CI. Lower certified CIs lead to more profit or revenue being attributed to electricity, and thus more of the dairy-related emissions being allocated to it, but not enough to wipe out the lower initial CI entirely.

average CI without allocation and zero-CI values, both shown previously in Figure 3. One advantage of profit-based coproduct allocation becomes apparent with this visualization: It leads to the flattest profit for farms greater than 500 head, indicating that this method is the best choice to reduce the market distortion favoring larger dairies currently caused by the LCFS. More broadly, any of the studied alternatives (i.e., zero CI, revenue-based coproduct allocation, or profit-based coproduct allocation) would reduce the tremendous imbalance in profits available to larger farms.

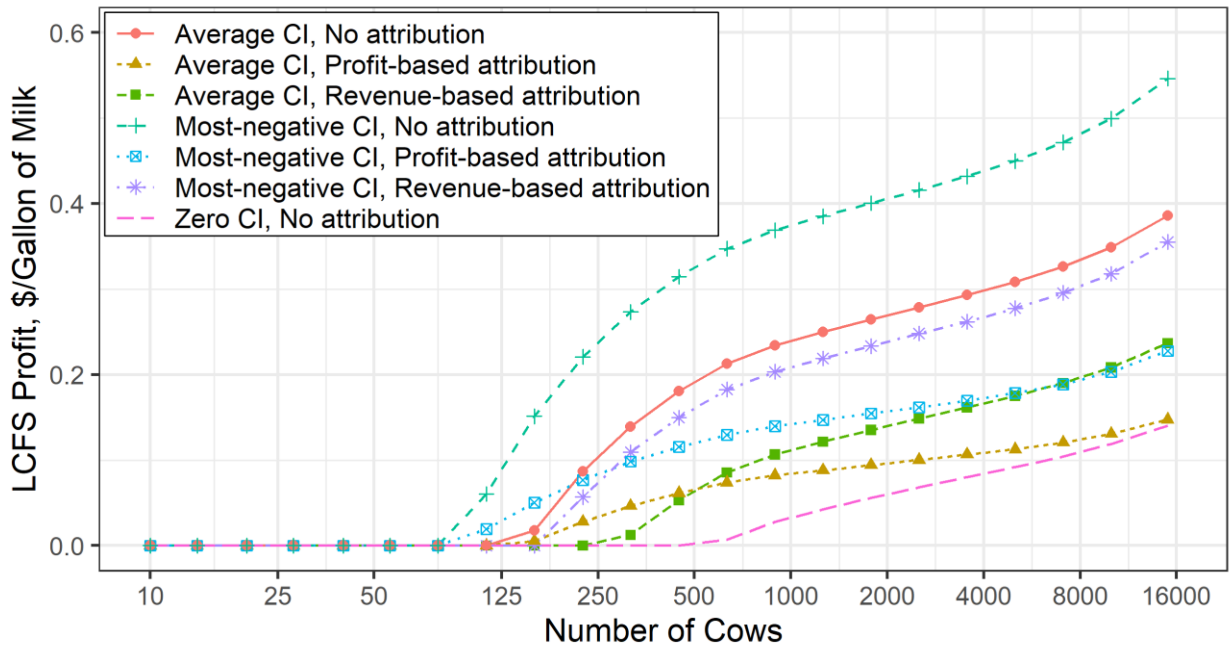

Figure 7. LCFS profit to dairies per gallon of milk under seven different CI conditions. The first half of each legend entry indicates the original CI, and the second half indicates which, if any, method was used to update the CI. Note that the x-axis is logarithmic. The point of departure from $0/gallon indicates the farm size at which electricity generation becomes profitable at a given CI.

4. Discussion

For farms above 1,000 head, attributing milk LCA emissions via revenue or value results in significant increases to pathway CIs, by 300 to 600 gCO_2e/MJ, depending upon farm size and whether profit or revenue is used in allocation. This is not enough to bring calculated CIs above zero, though they approach zero for large farms using profit-based allocation. Thus, implementing coproduct allocation would still allow dairies to generate significant revenue and profit under the LCFS, but at a reduced level compared to today. Using either a revenue- or a value-based coproduct allocation approach appears to be viable, though the former has the advantage of requiring much less knowledge of farm-specific economic factors while the latter is better at removing the market distortion which presently supports large operations (though it by no means eliminates it). This market distortion leads to two probable outcomes: First, dairies are incentivized to consolidate in order to take advantage of the economies of scale. Second, dairies are incentivized to purchase more cows, independent of consolidation. The resulting trend is expected to be one of an increased number of animals across the state *and* a greater size of individual herds, both of which were already happening before creation of the LCFS, as shown in Figure 1. If profit-based coproduct allocation is used, it is also tremendously sensitive to dairy and bioelectricity economics and therefore requires a deep look into the technical and accounting factors of these operations.

There is also a third, and very important, outcome created by the LCFS, and that is an incentive towards worse manure handling practices as a baseline. A farm which at present allows its herd to range free and deposit manure without aggregation does not have methane emissions from manure management to mitigate, and thus cannot generate the significant profits identified herein. That farm is being penalized for its lower-impact practices and is incentivized to confine its cattle and aggregate their manure into a methane-emitting pond, which enables it to then receive LCFS credits in exchange for capture and combustion of this methane. Moreover, insofar as smaller farms may be less likely to manage their manure in lagoons, this factor exacerbates the market distortion created by LCFS preferencing larger cattle farming operations.

4.1. Comparison to Existing Literature

Aaron Smith [30] performed a comparison of dairy revenue and energy revenue for a 2,000-cow dairy, with similar costs and revenue to those identified in our study. Notably, Smith assumes a pipeline injected compressed natural gas (CNG) pathway for the fuel, whereas we assume a cheaper electricity pathway (though we also provide some of our own analysis for CNG pathways in Appendix A), leading to distinct, but similar results. As Smith says, "[e]qual numbers of California digesters are employed to produce CNG for transportation and to generate electricity."

Smith uses a cost of $636 per cow-year[11] and a CNG revenue of $1,935 per cow-year. In our model, a 2,000-cow dairy would have a capital payment of $234/cow-year[12], and an operational expense of $123. However, since Smith's analysis entails the much more expensive process of upgrading to CNG for pipeline injection, we also looked at the underlying data used [31], which apply a capital cost of $2.9 million for the digester and an operational cost of $174,000. These estimates are slightly below our estimates of $3.3 million in capital expense and $186,000 in annual operational costs for a 2,000-cow dairy.

In comparison to our estimates of CNG cost, our total cost per cow-year is $882, with $302 due to operational expenses. The former is quite a bit higher than Smith's estimate of $636 while the latter is quite close to his estimate of $294.

We estimated an LCFS credit value of $951/cow-year and $1,320/cow-year in our average and most-negative CI cases for electricity, respectively, less than Smith's estimate of $1,935. More comparable are our estimates for CNG, which are also much closer to Smith's, at $1,400 and $2,190 per cow per year in the average and most-negative cases, respectively.

In summary, while Smith does not account for capex cost in his analysis, and assumes a more expensive pathway than we do, these two assumptions approximately cancel out, leading to a cost of $294/cow-year, 82% of our estimate of $357/cow-year. LCFS credit revenues per cow, on the other hand, are much

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11 $294 from operations and $342 from capital, which Smith eliminates because these are often grant funded. Smith also uses a higher CRF of 0.142 compared to the 0.117 which we used.

12 $284 with a CRF of 0.142.

higher in Smith's analysis, 50% to 100% larger than ours due to the low conversion efficiency of electricity production.

5. Conclusions & Policy Recommendations

This model provides only a second-order estimate of the costs, revenues, profits, and emissions from dairies, all of which depend on case-specific factors which we have not characterized, including: varying labor costs, feed choices, animal breed, confinement, the availability of grants for digester capital costs, and much more.

As it stands, our analysis indicates that the LCFS is offering a significant competitive advantage to large-scale dairy operations over smaller-scale operations, and that profits are available only to farms with poor (i.e., methane generating) manure handling practices. We estimate that the value of subsidy available to a 10,000-cow farm range from \$0.35 to \$0.50 per gallon of milk, which is 1.5 to 1.8 times that available to a 500-head farm assuming the same certified CIs for both facilities. Furthermore, our economic analysis indicates that a small, 100-cow, farm would derive little to no value from LCFS, regardless of avoided methane emissions when producing bioelectricity, even when confining their cattle and aggregating manure into methane-generating ponds. This creates clear market distortions in favor of large, confined operations, which could exacerbate the already-present trend of market consolidation. Furthermore, this study illustrates that the negative emissions associated with use of anaerobic manure digestion are at least in part an artifact of accounting choices that increase the revenue particularly to large dairy operations. These include the policy of considering manure to be a true waste from an LCA standpoint even where it accounts for a significant portion of total revenue, and the base-case assumption of uncontrolled methane release. We recommend one of three possible approaches to alleviate the above concerns:

1. Carbon intensity for CNG and electricity derived from anaerobic digestion of cow manure could be limited to zero. This would reduce subsides to many farms from as high as \$0.57/gallon to \$0.16/gallon of milk. Per our model, farms larger than 580 head would still be incentivized to produce electricity, and grants could be used to assist smaller farms with manure management practices (whether through capture and destruction of methane or via elimination of the anaerobic decomposition which creates methane in the first place) as well as to account for differences between this model and the reality on the ground.
2. Farms could be required to flare rather than vent biogas generated by manure as a baseline. This would have a similar impact to the option above, since it would mean the carbon intensity of generated electricity would be close to zero rather than significantly negative.
3. LCFS pathways could use coproduct allocation to account for the lifecycle emissions of dairy production in the CIs calculated for manure-based bioelectricity. We calculate that this would lead to a lower limit of CI values for farms above 500-head of cattle of -400 gCO_2e/MJ compared to present day values as low as -762 gCO_2e/MJ. This could lead to a stable condition in which large profits from bioelectricity lead to higher CIs of manure-based bioelectricity and vice-versa, stabilizing the generation of credits, but this would require a more detailed study to fully assess. Using either a revenue- or a value-based coproduct allocation approach appears to be viable, though the former has the advantage of requiring much less knowledge of farm-specific economic factors, while the latter is better at removing the market distortions which presently support large operations.

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Appendix

Appendix A Comparison Between Compressed Natural Gas and Electricity Generation

Several factors affect the relative economics of electricity and compressed natural gas (CNG) pathways from dairy-manure. The first are the certified CIs in the LCFS, which are smaller in magnitude among present CNG pathways: While approved electricity pathways have an average value of -461 gCO_2e/MJ and a lowest value of -762 gCO_2e/MJ, CNG pathways have an average value of -309 gCO_2e/MJ and a lowest value of -533 gCO_2e/MJ [5]. Second, compressed natural gas vehicles have an EER of 0.9 or 1, relative to EERs between 2.6 and 5 for electric vehicles. Third, the costs associated with biogas upgrading into natural gas and pipeline injection[13] differ from the costs of onsite production. The first two of these factors are captured in the subsidy levels shown in Figure A-1 while the third factor is captured in the production cost curves.

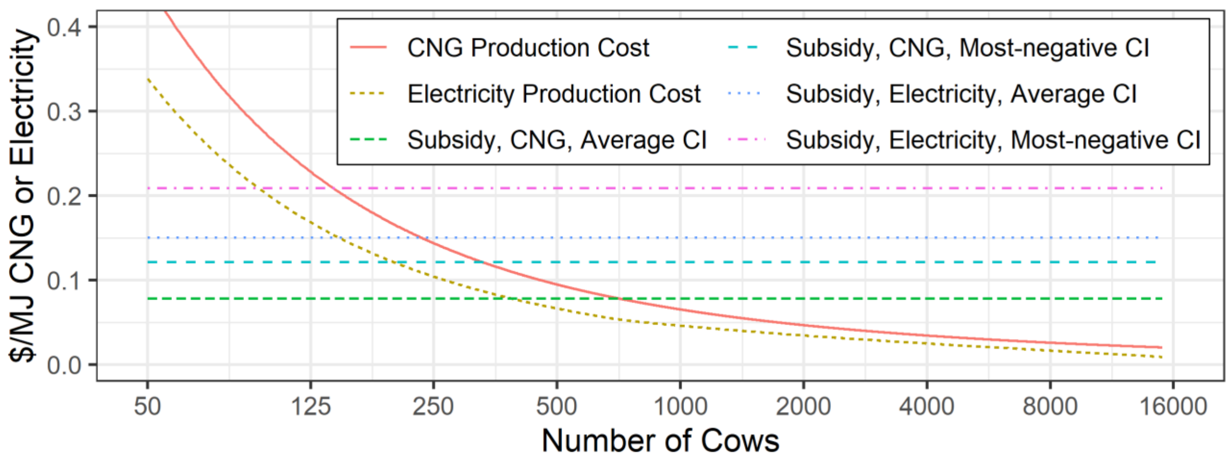

Figure A-1. Net production cost (total cost minus revenue from energy sales) and LCFS credit revenues (i.e., subsidy) by farm size. Note that the x-axis is logarithmic. CNG refers to pipeline injected compressed natural gas.

Significantly, the production cost per unit is higher for CNG while the revenues under the LCFS would be lower. On the other hand, due to the inefficiencies of combustion engines, many more units of energy could be sold in the CNG case — 2.7 times as many for a representative 2,000 cow dairy — raising the potential for higher total profits, though lower profit margins, for CNG. It is important to keep in mind that this lower profit margin is reflective only of the CNG generation process and not of the dairy operation as a whole—it is possible that, due to the higher total revenues from CNG, the dairy operation's profit margins are improved relative to the electricity operation.

These higher total profits are shown to actualize in Table A-1, which reproduces the result of Table 2 for the average and most-negative cases alongside the equivalent values for two CNG pathways. LCFS profit per gallon of milk is generally lower for CNG pathways than for electricity pathways except for relatively

[13] Natural gas upgrading and pipeline costs from Parker et al. [12] assuming an average interconnection distance of 2 miles, approximately the average value in Jaffe et al. [32]

large farms (i.e., over 1,000-head) with the most-negative certified CIs. Here, the CNG pathway could enable up to 30% increased total profit (or profit per gallon of milk, as shown) from fuel production compared to the electricity pathway. While the higher revenues do not significantly alter the picture, the increase in relative profit between medium and large farms (e.g., 1,000 and 10,000 head) is noteworthy. CNG pathways under the LCFS appear to magnify the identified market distortion (see Section 4) in further favor of large operations. However, this effect is mitigated somewhat by the fact that it only affects the exceptionally negative CI case, and not average or subaverage CIs.

Table A-1. LCFS credit profit per gallon of milk across farm sizes, certified CI, and fuel type.

	LCFS Profit, $/Gallon of Milk - Electricity		LCFS Profit, $/Gallon of Milk - CNG	
Number of Cows	Most-negative CI (-762 gCO2e/MJ)	Average CI (-461 gCO2e/MJ)	Most-negative CI (-533 gCO2e/MJ)	Average CI (-309 gCO2e/MJ)
100	$0.02	$0.00	$0.00	$0.00
500	$0.33	$0.19	$0.18	$0.00
1,000	$0.37	$0.24	$0.37	$0.08
2,000	$0.41	$0.27	$0.50	$0.21
10,000	$0.50	$0.35	$0.65	$0.36
15,000	$0.55	$0.39	$0.67	$0.38

Appendix B Electricity Generation Model Details

We built cost and productivity estimates for farms from a single cow up to 15,000 cows. We then calculated the resulting biogas production for each farm size using the biogas production and methane concentration [33] of each farm and heating value of methane of 1,012 BTU/scf.

Digester capital and annual costs were calculated from Parker et al. [12], assuming that each farm purchases its own stirred tank digester [12].

To assess conversion from biogas to electricity, we created an economic model based on Jaramillo & Matthews' [19] generator data. Their paper provides point estimates of heat rate, operational expenses, and annual expenses for five scales each of reciprocating engine and gas turbine. Because a more efficient engine will generate more revenue under the LCFS, we applied only the more efficient (though also more expensive) reciprocating engines in our model.

The 15,000-cow farm produces 64% as much biogas as the largest engines in Jaramillo & Matthews can handle, but the smallest farms extrapolate capital and annual costs below that of their smallest engines. We therefore limited our linear model, capping values which extrapolated outside the range provided (i.e., heat rate, total annual cost and total capital cost were limited to their lowest reported values). We used a capacity factor of 93% [34] to determine necessary engine size, which resulted in the linear models summarized in Table B-1 and Figure B-1 after converting to 2021 dollars.

Table B-1. Linear model created from reciprocating engine data [19].

Parameter	Unit	Equation (flow_rate in mmbtu/hr)	Minimum Value
Capital cost	$2021	$172,710*flow_rate-$19,852	$236,643
Annual cost	$2021	$14,192*flow_rate-$469	$23,414
Heat rate	mmbtu/MWh	0.0572*flow_rate + 11.0	8.758

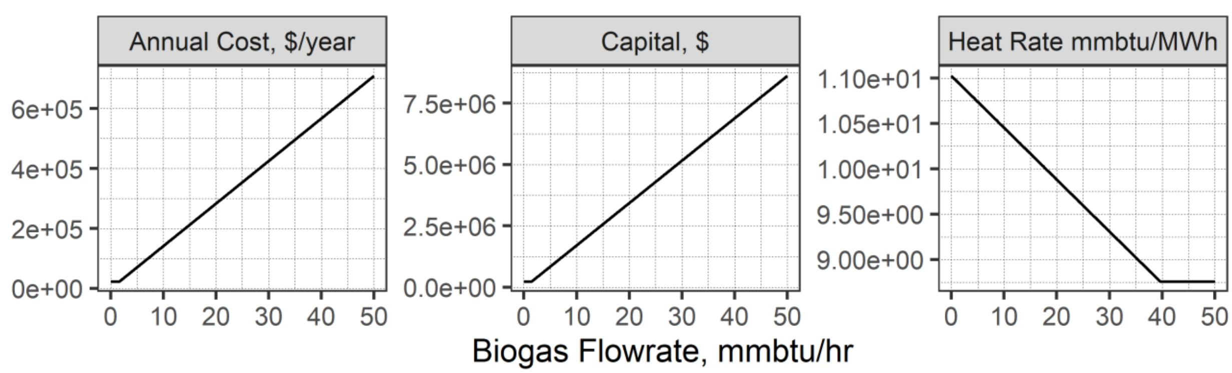

Figure B-1. Linear model created from reciprocating engine data [19].

We then calculated total annual costs by annualizing digester and engine capital costs using a capital recovery factor of 0.117, consistent with 15-year financing at an 8% interest rate, and adding this to the annual expenses in Jaramillo & Matthews [19] and Parker et al. [12] for engines and digesters, respectively. From the annual costs, we subtracted the revenue from electricity sales, assuming electricity is sold at $79 /MWh[14], to determine the annual net cost of building and running the AD and onsite combustion operation.

We then calculated the net electricity production cost (before LCFS credits) per MJ of electricity, by dividing this total cost by the annual electricity production for each farm size.

14 We used the generation-weighted average power price for the 51 California power plants in the 2019 EIA Power Plant Operations dataset [20] which report using at least 50% qualifying biofuels as feedstock. This yielded a wholesale price of bioelectricity of $78.59/MWh (SD: $34.24). This is a relatively high price for wholesale power, but it is reflective of current market conditions. In part, these high prices may reflect the value of bundled Renewable Energy Credits (RECs) generated under CA's Renewable Portfolio Standard as well as other price supports such as Feed-in Tariffs or Production Tax Credits that are available in some jurisdictions.

Attach. 8

SCIENCE POLICY

$PM_{2.5}$ polluters disproportionately and systemically affect people of color in the United States

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Racial-ethnic minorities in the United States are exposed to disproportionately high levels of ambient fine particulate air pollution ($PM_{2.5}$), the largest environmental cause of human mortality. However, it is unknown which emission sources drive this disparity and whether differences exist by emission sector, geography, or demographics. Quantifying the $PM_{2.5}$ exposure caused by each emitter type, we show that nearly all major emission categories—consistently across states, urban and rural areas, income levels, and exposure levels—contribute to the systemic $PM_{2.5}$ exposure disparity experienced by people of color. We identify the most inequitable emission source types by state and city, thereby highlighting potential opportunities for addressing this persistent environmental inequity.

INTRODUCTION

Ambient fine particulate matter air pollution ($PM_{2.5}$) is responsible for 85,000 to 200,000 excess deaths per year in the United States (*1*, *2*), with health effects observed even at concentrations below the current national standard of 12 μg m^{-3} (*3*–*5*). Racial-ethnic and socioeconomic disparities in air pollution exposure in the United States are well documented (*6*–*10*) and have persisted despite overall decreases in $PM_{2.5}$ pollution (*11*–*13*).

Most evidence of exposure disparity relies on measured or empirically modeled ambient concentrations or on assessment of proximity to industrial or roadway emission sources (*6*, *10*, *12*–*20*). From the existing evidence, however, it is not possible to determine the relative contributions of different source types to racial-ethnic disparity in exposure to $PM_{2.5}$. Here, we model anthropogenic sources of $PM_{2.5}$ exposure resolved by race and ethnicity and show that nearly all major emission source sectors disproportionately affect people of color (POC).

We estimate exposure impacts for each emission source type on five racial-ethnic groups based on the U.S. Census: White (62% of the population), Black (12%), Hispanic (17%), Asian (5%), and POC (38%; see Materials and Methods for details). As a proxy for exposure to $PM_{2.5}$, we calculate population-weighted average ambient $PM_{2.5}$ concentrations for each race-ethnicity based on census-designated residential location.

We examine exposure disparity—the population-weighted concentration difference between each racial-ethnic group and the population average—in relative (percent) and absolute (μg m^{-3}) terms. Sources with the highest relative disparity may yield the largest disparity mitigation per unit mass of emission reduction, whereas sources with the highest absolute disparity may have the greatest potential for overall disparity reduction.

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RESULTS

Results indicate that emission sources that disproportionately expose POC are pervasive throughout society. Estimated year 2014 total population average $PM_{2.5}$ exposure from all domestic anthropogenic sources is 6.5 μg m^{-3} in the contiguous United States; exposures are higher than average for POC, Blacks, Hispanics, and Asians (7.4, 7.9, 7.2, and 7.7 μg m^{-3}, respectively; Fig. 1, B to E) and lower than average for Whites (5.9 μg m^{-3}; Fig. 1A). Whites are exposed to lower-than-average concentrations from emission source types causing 60% of overall exposure (Fig. 1A), with an overall relative exposure disparity of −8% (−0.55 μg m^{-3} absolute disparity) compared with the population average. Conversely, POC experience greater-than-average exposures from source types, causing 75% of overall exposure (Fig. 1B); their overall exposure disparity is 14% (0.90 μg m^{-3}). Blacks are exposed to greater-than-average concentrations from source types contributing 78% of exposure (Fig. 1C), with an overall exposure disparity of 21% (1.36 μg m^{-3}). Hispanics and Asians are disparately exposed to $PM_{2.5}$ from 87 and 73% of sources, respectively, and experience 11% (0.72 μg m^{-3}) and 18% (1.20 μg m^{-3}) overall exposure disparities, respectively (Fig. 1, D and E).

Grouping the source types (Fig. 1, A to E) into 14 source sectors (Fig. 1, F to J) reveals that source types that disproportionately expose POC, Blacks, Hispanics, and Asians to higher-than-average concentrations are dominant in most sectors. Whites are exposed to lower-than-average concentrations from most emission sectors (Fig. 1F). Blacks are exposed to higher-than-average concentrations from all sectors (Fig. 1H).

Of the emission source sectors that cause the largest absolute disparities, four out of the top six source sectors are the same for POC, Blacks, Hispanics, and Asians: industry, light-duty gasoline vehicles, construction, and heavy-duty diesel vehicles (Fig. 1, G to J). Residential gas combustion and commercial cooking are among the largest sources of relative disparities for all four groups (e.g., 41 and 35%, respectively for POC; Fig. 1, G to J). The only sectors that affect Whites substantially more than average are coal electric generation and agriculture (8 and 4% relative disparity, respectively; Fig. 1F). Consistent with previous findings (*11*, *21*), we find that POC, Hispanics, and Asians are exposed to less $PM_{2.5}$ from coal electric generators than average (−13%, −38%, and −18%, respectively), and Blacks are exposed to 18% more than average (Fig. 1H).

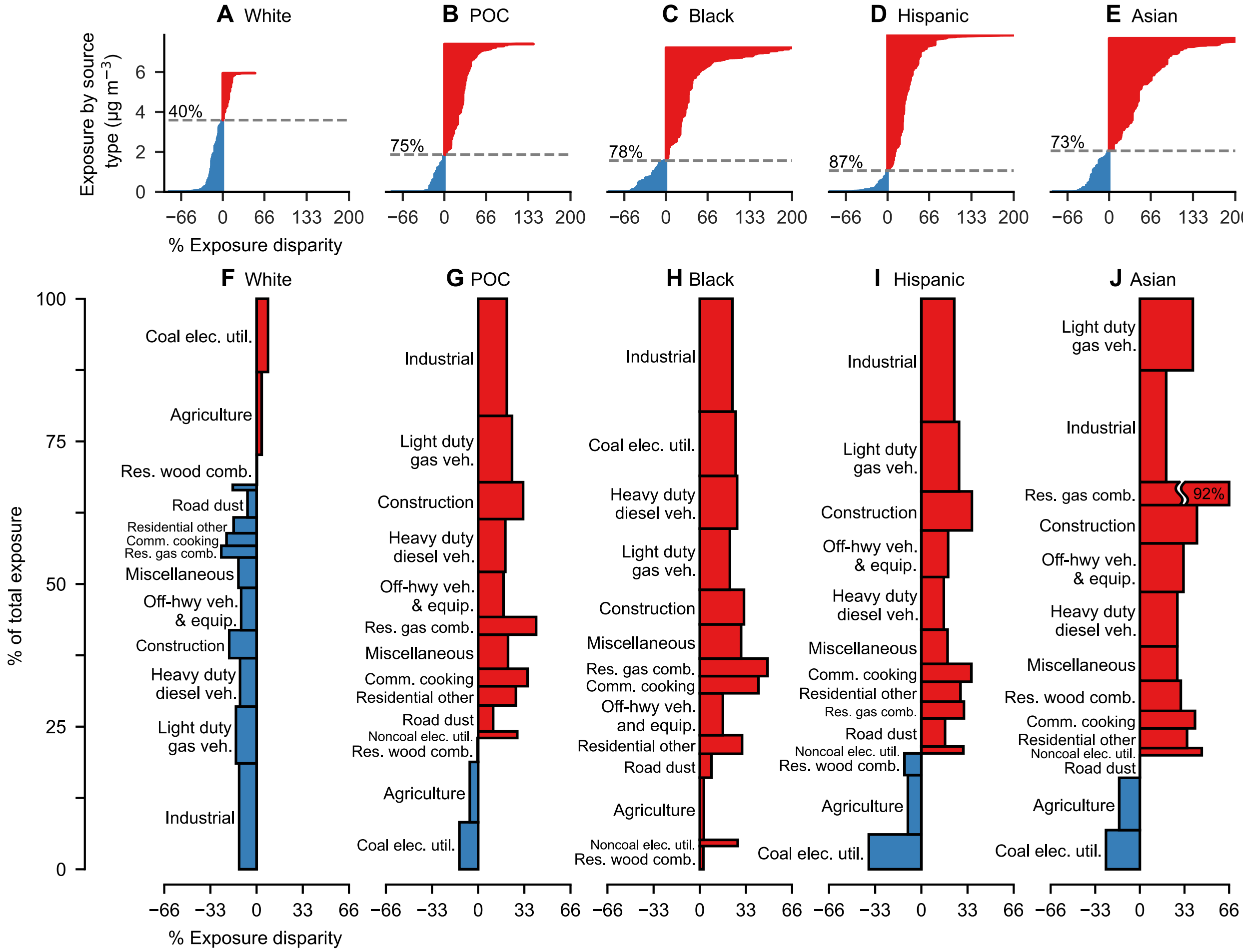

Fig. 1. Source contributions to racial-ethnic disparity in $PM_{2.5}$ exposure. (**A** to **E**) Individual source type ($n = 5434$ source types) contributions to exposure (*y* axis) and % exposure disparity (*x* axis, truncated at 200%, positive values are shaded red, negative values are shaded blue), with dashed lines denoting percent exposure caused by sources with positive exposure disparity. (**F** to **J**) Sources in (A) to (E) grouped into source sectors ($n = 14$ groups) and ranked vertically according to absolute exposure disparity, proportional to the area of each rectangle. As shown in (B), POC experience greater-than-average exposures from source types causing 75% of overall exposure. Source: data file S1, which also includes results for individual states and urban areas.

Nationally, racial-ethnic exposure disparities are not caused by a small number of emission sources; instead, most source types and sectors result in higher-than-average exposures for POC and lower-than-average exposures for Whites (Fig. 1). By examining the percent of exposures caused by these disproportionately exposing emission source types for each group [for example, 40% for Whites (Fig. 1A) and 75% for POC (Fig. 1B) nationally], we find that this is also largely true within individual U.S. states, within individual urban and rural areas, across incomes, and across exposure levels (Figs. 2 and 3).

In 45 of the 48 states studied, disproportionately exposing sources cause the majority of POC exposure (Fig. 2A). In the (population-weighted) average state, 78% of exposure is caused by sources that disproportionately expose POC (White: 29%; Black: 77%; Hispanic: 73%; and Asian: 75%; Figs. 2A and 3, C to E; these average-state disparities differ from the national average disparities above because national averages include disparities occurring among states in addition to within states).

We observe the same effect within urban areas (Fig. 2B), with 73% of exposure in the (population-weighted) average urban area caused by sources that disproportionately expose POC (White: 31%; Black: 71%; Hispanic: 71%; and Asian: 56%; Figs. 2B and 3, H to J). There is a notable exception: Asians are less exposed than average in many urban areas in California with large Asian populations (data file S1; for example, Los Angeles, San Francisco, and San Jose). In the (population-weighted) average urban area outside California, 67% of Asian exposure is caused by source types that disproportionately expose Asians, compared with 56% when including California. Disparities also consistently occur in rural areas (defined here as the complement of urban areas), where a large proportion of exposure is caused by sources that disproportionately expose POC (White: 39%; POC: 62%; Black: 63%; Hispanic: 57%; and Asian: 74%; Figs. 2C and 3, M to O). However, disparities in rural areas are not as pronounced as in urban areas (Fig. 2, B and C).

Last, systemic disparity exists at all income levels. Consistent with a large body of evidence (*12*, *22*), we find that racial disparities are not simply a proxy for economic-based disparities. POC at every income level are disproportionately exposed by the majority of sources, with a population-weighted average across income bins of 76% of exposure caused by source types that disproportionately

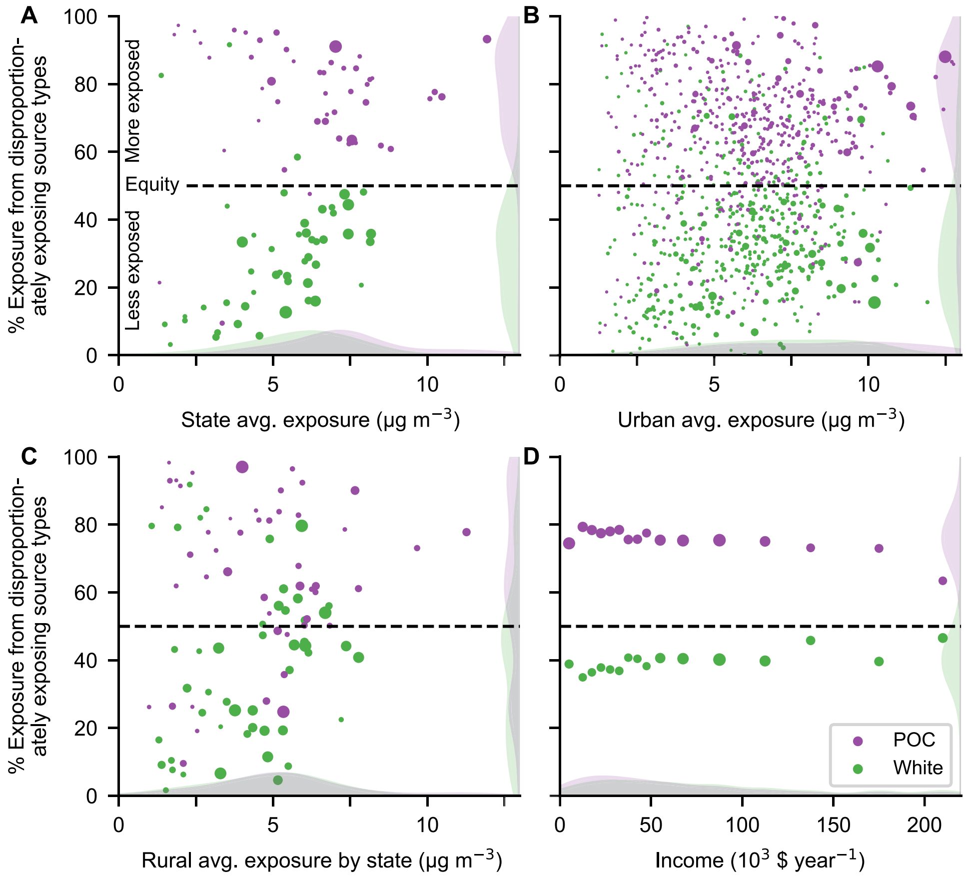

Fig. 2. Percent of $PM_{2.5}$ exposure caused by emission source types that disproportionately expose people of color (POC) and Whites. Data shown for (**A**) U.S. states ($n = 48$ states), (**B**) urbanized areas ($n = 481$ areas), (**C**) rural areas in each state ($n = 48$ states), and (**D**) income bins ($n = 16$ bins; last bin is >\$200,000). Icon area is proportional to population; shaded areas are kernel density estimates. A *y* axis value of 50% would represent equity for that group (i.e., for the population-average exposure), meaning that half of their exposure comes from source types that disproportionately expose them and the other half is from source types that expose them less than average. Across geographies and levels of exposure (A to C), as well as incomes (D), most emission sources consistently result in higher exposures for POC and lower exposures for Whites. Source: data file S2.

expose POC (Fig. 2D and fig. S1). Exposures vary more by race-ethnicity than by income: The difference in average exposure between POC and Whites is 2.4 times larger than the range in average POC exposure among income levels (data files S1 and S2).

DISCUSSION

Our results come with caveats. First, we use emission amounts and locations, reduced complexity air quality modeling, and population counts that all contain previously quantified uncertainty (*11*, *23*; Supplementary Text). However, our core findings are consistent across states, urban and rural areas, and concentration levels, rendering it improbable that they are attributable to model or measurement bias. Second, because aggregate results are more robust than results for any single location, we recommend additional analysis incorporating local data and expertise before local actions are taken. Third, our results for states and for urban and rural areas reflect exposure to ambient $PM_{2.5}$, including contributions from emission sources located outside the state, urban area, or rural area. This has implications for local authorities, who may not have jurisdiction over all sources of their exposure. Last, this analysis focuses on outdoor concentrations at locations of residence. Disparities in associated health impacts would also reflect racial-ethnic variability in mobility, microenvironment, outdoor-to-indoor concentration relationships, dose-response, access to health care, and baseline mortality and morbidity rates.

We have shown here that most emission source types—representing ~75% of exposure to $PM_{2.5}$ in the United States—disproportionately affect racial-ethnic minorities. This phenomenon is systemic, holding for nearly all major sectors, as well as across states and urban and rural areas, income levels, and exposure levels. Industry, light-duty gasoline vehicles, construction, and heavy-duty diesel vehicles are often among the largest sources of disparity, but this can vary widely by source type and location. Because of a legacy of racist housing policy (fig. S2; supporting results) and other factors, racial-ethnic exposure disparities have persisted even as overall exposure has decreased (*11*–*13*). Targeting locally important sources for mitigation could be one way to counter this persistence. We hope the information provided here can help guide national, state, and local stakeholders to design policies to efficiently reduce environmental inequity.

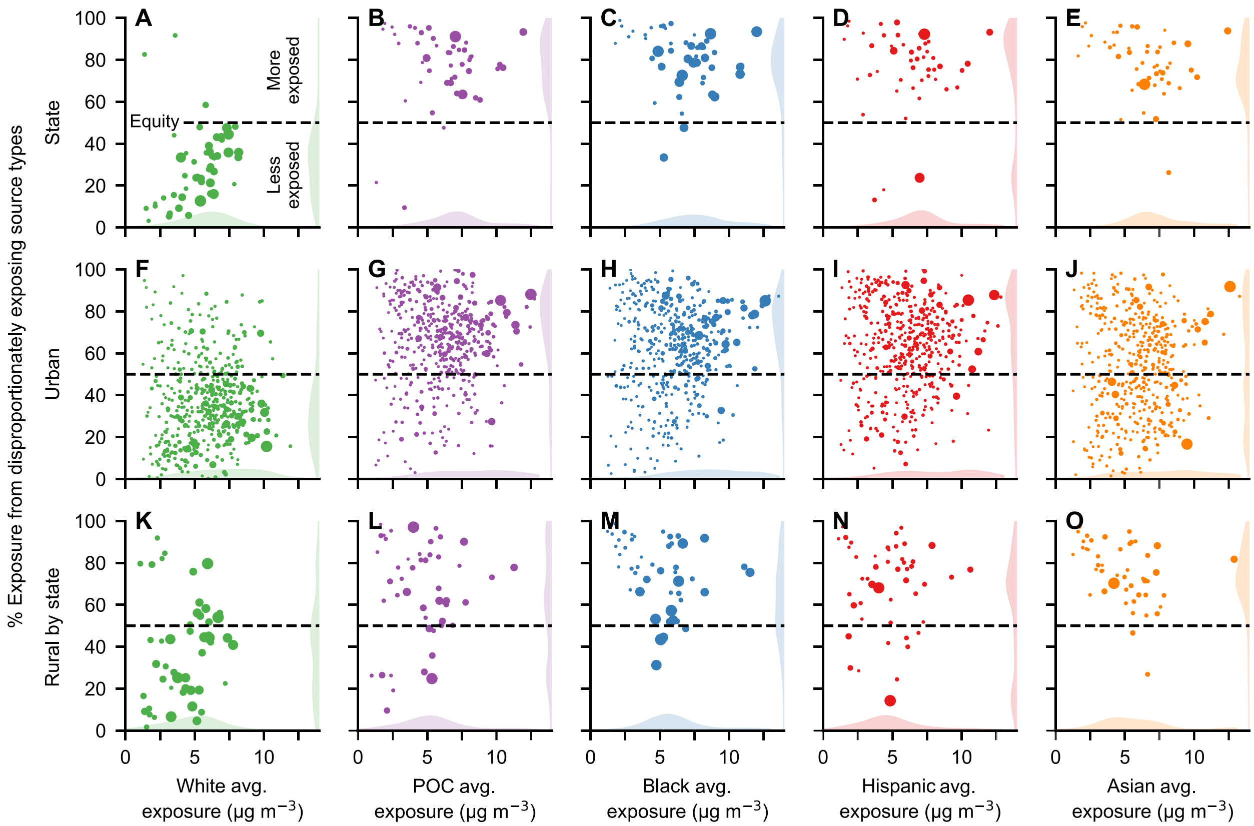

Fig. 3. Percent of $PM_{2.5}$ exposure caused by emission source types that disproportionately expose each racial-ethnic group by location and race-ethnicity. Icon area is proportional to population; shaded areas are kernel density estimates. This figure is analogous to Fig. 2 but with results for all five racial-ethnic groups. Source: data file S2.

MATERIALS AND METHODS

We use a source-receptor matrix (*24*) created using the InMAP (*25*) air quality model to independently estimate concentrations in the contiguous United States resulting from anthropogenic emissions. We consider all 5434 source types [i.e., all U.S. Environmental Protection Agency (EPA) Source Classification Codes (SCCs) with nonzero emissions; we exclude the 8378 SCCs without emissions associated with them] in the 2014 EPA National Emissions Inventory (NEI) v1. County-level emissions are allocated to individual grid cells within the county using spatial surrogates. Emissions processing is described in further detail by Tessum *et al.* (*11*). To focus on impacts from modifiable factors, we do not investigate here emissions from biogenic, wildfire, or international sources. Exposure and health impacts resulting from these additional sources are quantified by Tessum *et al.* (*11*).

We investigate both primary (i.e., directly emitted) and secondary (i.e., formed in the atmosphere from other emissions) $PM_{2.5}$. We model secondary $PM_{2.5}$ formed from volatile organic compounds, oxides of nitrogen and sulfur (NO_x and SO_x), and ammonia (NH_3). We aggregate the 5434 SCCs (source "types") into 14 source sectors (table S1), each accounting for >1% of total $PM_{2.5}$ exposure. InMAP predicts concentrations at a spatial scale ranging from 48 km in areas with low population density to as fine as 1 km in urban centers; this intraurban spatial scale is necessary to resolve differences in exposure among demographic groups (*26*). The population-weighted average horizontal grid cell edge length is 10.8 km nationwide and 3.4 km in urban areas. Additional grid statistics can be found in table S2.

The source-receptor matrix relates emissions in any one location in a gridded spatial domain to InMAP-computed concentrations in all other locations. These relationships are generated with independent simulations of the air quality model for each of over 50,000 grid cells covering the contiguous United States for both ground-level and elevated sources.

Population-weighted average ambient concentrations, our measure of exposure, are calculated using a conventional approach to weighted averages. Specifically, we first multiply, for each grid cell, the population and the concentration. The sum of those values across all cells in the given spatial domain is then divided by the corresponding population to yield the population-weighted average concentration: $PWA = \Sigma(PC)/\Sigma(P)$. Here, PWA is the population-weighted average, P is the population in a grid cell, C is the concentration in a grid cell, and the summations in the numerator and denominator are across all grid cells in the geography being studied (e.g., in a state, in the contiguous United States).

Population data by race-ethnicity are from the U.S. Census 2012–2016 American Community Survey (ACS) at Census Block Group level of spatial aggregation. We focus on the four largest race-ethnicity groups as determined by self-identification in the Census: Asian, Black or African American, Latino or Hispanic, and White. We aggregate these four population subgroups such that they are mutually exclusive: "Hispanic" including people of all races who identify as having Hispanic or Latino origin, and the other three groups (Asian, Black, and White) referring only to non-Latino/non-Hispanic persons. POC are defined herein as everyone except non-Latino/non-Hispanic Whites (i.e., individuals identifying as Hispanic plus non-Hispanic individuals identifying as Black or African American, American Indian or Alaska Native, Asian, Native Hawaiian and other pacific islander, some other race, or two or more races).

The 2012–2016 ACS provides income statistics by Census Tract, with 16 household income categories (lowest: "less than $10,000"; highest: "$200,000 or more"). We use the proportion of households in each income category to estimate population counts at the finest available level of race-ethnicity information: White and POC. Table S3 details the population distribution by income category.

To calculate exposure in individual urban areas, we use year 2018 urbanized area extents as defined by the U.S. Census (www.census.gov/geographies/mapping-files/time-series/geo/carto-boundary-file.html). We define "rural" as everywhere that is not within an urbanized area extent.

To calculate exposure by 1930s-era Home Owners' Loan Corporation (HOLC) grades, we use historical maps digitized by the Mapping Inequality project (*27*). HOLC maps classify urban neighborhoods into four grades: A (green; "best"), B (blue; "still desirable"), C (yellow; "definitely declining"), and D (red; "hazardous"). For results shown in fig. S2, we define "% exposure from disproportionately exposing source types" as the percent of exposure that is caused by source types that expose residents of a given race-ethnicity currently living in an area with the given historical HOLC grade in a given city more than the overall average exposure of all residents of HOLC-graded areas in that city.

SUPPLEMENTARY MATERIALS

Supplementary material for this article is available at http://advances.sciencemag.org/cgi/content/full/7/18/eabf4491/DC1

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Science Advances

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Attach. 9

Study Finds Exposure to Air Pollution Higher for People of Color Regardless of Region or Income

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In the United States, people of color breathe more particulate air pollution on average, a finding that holds across income levels and regions of the US, according to a study by researchers at the EPA-funded Center for Air, Climate, and Energy Solutions. The findings expand a body of evidence showing that African Americans, Hispanics, Asians, and other people of color are disproportionately exposed to a regulated air pollutant called fine particulate matter ($PM_{2.5}$).

The findings, published in April 2021 in *Science Advances*, have serious public health implications–exposure to $PM_{2.5}$ can cause lung and heart problems, especially for those with chronic disease, younger people, older people, and other more vulnerable populations.

The researchers conducted modeling and analyzed EPA data from the National Emissions Inventory for more than 5,000 emission source types for $PM_{2.5}$ such as industry, agriculture, light- and heavy-duty vehicles, construction, residential sources, and road dust to determine which source(s) were causing inequal exposure to $PM_{2.5}$ pollution by race-ethnicity.

They found racial-ethnic disparities for nearly all major emission categories. White people are exposed to lower than average concentrations from emission source types causing 60 percent of overall exposure, whereas people of color experience greater than average exposures from source types causing 75 percent of overall exposure. The disparity generally held across states and urban and rural areas and occurs for people at all income levels.

In other words, the study found that race appears to be an important factor for exposure in nearly all regions.

“Some assume that when there is a systematic racial-ethnic disparity, such as the one we see here, that the underlying cause is a difference in income,” says lead author Christopher Tessum of the University of Illinois. “Because the data shows that the racial disparities hold for all income levels, our study reinforces previous findings that race/ethnicity, independently of income, drives air pollution-exposure disparities.”

Tessum said the results have implications for how regulations might be designed to effectively address environmental injustice for people of color exposed to air pollution from multiple source types.

“We find that nearly all emission sectors cause disproportionate exposures for people of color on average,” said co-author Julian Marshall, a professor of civil and environmental engineering at the University of Washington. The authors noted in the paper that because of a legacy of housing policy and other factors, racial-ethnic exposure disparities continue to persist even with a decrease in the overall exposure.

“The inequities we report are a result of systemic racism: Over time, people of color and pollution have been pushed together, not just in a few cases but for nearly all types of emissions,” said Marshall.

The study results also comes with caveats including uncertainty in the models and in inputs to the models and notes the potential benefit of additional analysis using local data and expertise. In addition, the study focuses on outdoor concentrations at locations of residence; disparities in associated health impacts would also reflect racial-ethnic variability in mobility, microenvironment, outdoor-to-indoor concentration relationships, dose-response, access to health care, and baseline mortality and morbidity rates.

EPA's goal is to provide an environment where all people enjoy the same degree of protection from environmental and health hazards and equal access to the decision-making process to maintain a healthy environment in which to live, learn, and work. To help achieve this, EPA researchers are focused on understanding the air quality concerns in overburdened communities and the health impacts of the residents. They are providing scientific expertise and tools to assist states, tribes, and communities to address environmental justice and equity issues, so that all people can breathe clean air and enjoy improved quality of life.

This research was funded by an EPA Science to Achieve Results grant: https://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractDetail/abstract_id/10614
<https://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractdetail/abstract_id/10614>

Reference:

Tessum, C. W., Paolella, D. A., Chambliss, S. E., Apte, J. S., Hill, J. D., & Marshall, J. D. (2021). PM2. 5 polluters disproportionately and systemically affect people of color in the United States. EXIT <https://advances.sciencemag.org/content/7/18/eabf4491> Science

Advances, 7(18), eabf4491.

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Attach. 10

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
AL	0109799999	1	97	METRO33660M33660	Mobile, AL MSA	Mobile County	61400	12900	14750	16600	18400	19900	21350	22850	24300	5160	Mobile County	Alabama	1
AL	0109999999	1	99	NCNTY01099N01099	Monroe County, AL	Monroe County	44200	11300	12900	14500	16100	17400	18700	20000	21300	9999	Monroe County	Alabama	0
AL	0110199999	1	101	METRO33860M33860	Montgomery, AL MSA	Montgomery County	65700	13800	15800	17750	19700	21300	22900	24450	26050	5240	Montgomery County	Alabama	1
AL	0110399999	1	103	METRO19460M19460	Decatur, AL MSA	Morgan County	63600	13400	15300	17200	19100	20650	22200	23700	25250	2030	Morgan County	Alabama	1
AL	0110599999	1	105	NCNTY01105N01105	Perry County, AL	Perry County	34700	11300	12900	14500	16100	17400	18700	20000	21300	9999	Perry County	Alabama	0
AL	0110799999	1	107	METRO46220N01107	Pickens County, AL HUD Metro FMR Area	Pickens County	53900	11350	12950	14550	16150	17450	18750	20050	21350	9999	Pickens County	Alabama	1
AL	0110999999	1	109	NCNTY01109N01109	Pike County, AL	Pike County	52500	11300	12900	14500	16100	17400	18700	20000	21300	9999	Pike County	Alabama	0
AL	0111199999	1	111	NCNTY01111N01111	Randolph County, AL	Randolph County	52200	11300	12900	14500	16100	17400	18700	20000	21300	9999	Randolph County	Alabama	0
AL	0111399999	1	113	METRO17980M17980	Columbus, GA-AL MSA	Russell County	62300	13100	15000	16850	18700	20200	21700	23200	24700	1800	Russell County	Alabama	1
AL	0111599999	1	115	METRO13820M13820	Birmingham-Hoover, AL HUD Metro FMR Area	St. Clair County	73100	15400	17600	19800	21950	23750	25500	27250	29000	1000	St. Clair County	Alabama	1
AL	0111799999	1	117	METRO13820M13820	Birmingham-Hoover, AL HUD Metro FMR Area	Shelby County	73100	15400	17600	19800	21950	23750	25500	27250	29000	1000	Shelby County	Alabama	1
AL	0111999999	1	119	NCNTY01119N01119	Sumter County, AL	Sumter County	43800	11300	12900	14500	16100	17400	18700	20000	21300	9999	Sumter County	Alabama	0
AL	0112199999	1	121	NCNTY01121N01121	Talladega County, AL	Talladega County	56700	11700	13350	15000	16650	18000	19350	20650	22000	9999	Talladega County	Alabama	0
AL	0112399999	1	123	NCNTY01123N01123	Tallapoosa County, AL	Tallapoosa County	56500	11900	13600	15300	16950	18350	19700	21050	22400	9999	Tallapoosa County	Alabama	0
AL	0112599999	1	125	METRO46220M46220	Tuscaloosa, AL HUD Metro FMR Area	Tuscaloosa County	67800	14250	16300	18350	20350	22000	23650	25250	26900	8600	Tuscaloosa County	Alabama	1
AL	0112799999	1	127	METRO13820N01127	Walker County, AL HUD Metro FMR Area	Walker County	64100	11700	13350	15000	16650	18000	19350	20650	22000	9999	Walker County	Alabama	1
AL	0112999999	1	129	NCNTY01129N01129	Washington County, AL	Washington County	49700	11300	12900	14500	16100	17400	18700	20000	21300	9999	Washington County	Alabama	0
AL	0113199999	1	131	NCNTY01131N01131	Wilcox County, AL	Wilcox County	43400	11300	12900	14500	16100	17400	18700	20000	21300	9999	Wilcox County	Alabama	0
AL	0113399999	1	133	NCNTY01133N01133	Winston County, AL	Winston County	47300	11300	12900	14500	16100	17400	18700	20000	21300	9999	Winston County	Alabama	0
AK	0201399999	2	13	NCNTY02013N02013	Aleutians East Borough, AK	Aleutians East Borough	77700	18200	20800	23400	25950	28050	30150	32200	34300	9999	Aleutians East Borough	Alaska	0
AK	0201699999	2	16	NCNTY02016N02016	Aleutians West Census Area, AK	Aleutians West Census Area	100100	21500	24600	27650	30700	33200	35650	38100	40550	9999	Aleutians West Census Area	Alaska	0
AK	0202099999	2	20	METRO11260M11260	Anchorage, AK HUD Metro FMR Area	Anchorage Municipality	97300	20950	23950	26950	29900	32300	34700	37100	39500	380	Anchorage Municipality	Alaska	1
AK	0205099999	2	50	NCNTY02050N02050	Bethel Census Area, AK	Bethel Census Area	56900	20650	23600	26550	29500	31900	34250	36600	38950	9999	Bethel Census Area	Alaska	0
AK	0206099999	2	60	NCNTY02060N02060	Bristol Bay Borough, AK	Bristol Bay Borough	102500	21550	24600	27700	30750	33250	35700	38150	40600	9999	Bristol Bay Borough	Alaska	0
AK	0206899999	2	68	NCNTY02068N02068	Denali Borough, AK	Denali Borough	110500	23250	26550	29850	33150	35850	38500	41150	43800	9999	Denali Borough	Alaska	0
AK	0207099999	2	70	NCNTY02070N02070	Dillingham Census Area, AK	Dillingham Census Area	65000	18200	20800	23400	25950	28050	30150	32200	34300	9999	Dillingham Census Area	Alaska	0
AK	0209099999	2	90	METRO21820M21820	Fairbanks, AK MSA	Fairbanks North Star Borough	93100	19600	22400	25200	27950	30200	32450	34700	36900	9999	Fairbanks North Star Borough	Alaska	1
AK	0210099999	2	100	NCNTY02100N02100	Haines Borough, AK	Haines Borough	80000	18200	20800	23400	25950	28050	30150	32200	34300	9999	Haines Borough	Alaska	0
AK	0210599999	2	105	NCNTY02105N02105	Hoonah-Angoon Census Area, AK	Hoonah-Angoon Census Area	74500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Hoonah-Angoon Census Area	Alaska	0
AK	0211099999	2	110	NCNTY02110N02110	Juneau City and Borough, AK	Juneau City and Borough	117800	24750	28300	31850	35350	38200	41050	43850	46700	9999	Juneau City and Borough	Alaska	0
AK	0212299999	2	122	NCNTY02122N02122	Kenai Peninsula Borough, AK	Kenai Peninsula Borough	89700	18850	21550	24250	26900	29100	31250	33400	35550	9999	Kenai Peninsula Borough	Alaska	0
AK	0213099999	2	130	NCNTY02130N02130	Ketchikan Gateway Borough, AK	Ketchikan Gateway Borough	87300	18350	21000	23600	26200	28300	30400	32500	34600	9999	Ketchikan Gateway Borough	Alaska	0
AK	0215099999	2	150	NCNTY02150N02150	Kodiak Island Borough, AK	Kodiak Island Borough	98400	20650	23600	26550	29500	31900	34250	36600	38950	9999	Kodiak Island Borough	Alaska	0
AK	0215899999	2	158	NCNTY02158N02158	Kusilvak Census Area	Kusilvak Census Area	38500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Kusilvak Census Area	Alaska	0
AK	0216499999	2	164	NCNTY02164N02164	Lake and Peninsula Borough, AK	Lake and Peninsula Borough	50700	18200	20800	23400	25950	28050	30150	32200	34300	9999	Lake and Peninsula Borough	Alaska	0

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AK	0217099999	2	170	METRO11260N02170	Matanuska-Susitna Borough, AK HUD Metro FMR Area	Matanuska-Susitna Borough	91400	19200	21950	24700	27400	29600	31800	34000	36200	9999	Matanuska-Susitna Borough	Alaska	1
AK	0218099999	2	180	NCNTY02180N02180	Nome Census Area, AK	Nome Census Area	55600	20650	23600	26550	29450	31850	34200	36550	38900	9999	Nome Census Area	Alaska	0
AK	0218599999	2	185	NCNTY02185N02185	North Slope Borough, AK	North Slope Borough	84900	18200	20800	23400	25950	28050	30150	32200	34300	9999	North Slope Borough	Alaska	0
AK	0218899999	2	188	NCNTY02188N02188	Northwest Arctic Borough, AK	Northwest Arctic Borough	62000	18200	20800	23400	25950	28050	30150	32200	34300	9999	Northwest Arctic Borough	Alaska	0
AK	0219599999	2	195	NCNTY02195N02195	Petersburg Borough	Petersburg Borough	79900	18200	20800	23400	25950	28050	30150	32200	34300	9999	Petersburg Borough	Alaska	0
AK	0219899999	2	198	NCNTY02198N02198	Prince of Wales-Hyder Census Area, AK	Prince of Wales-Hyder Census Area	67600	18200	20800	23400	25950	28050	30150	32200	34300	9999	Prince of Wales-Hyder Census Area	Alaska	0
AK	0222099999	2	220	NCNTY02220N02220	Sitka City and Borough, AK	Sitka City and Borough	89100	18750	21400	24100	26750	28900	31050	33200	35350	9999	Sitka City and Borough	Alaska	0
AK	0223099999	2	230	NCNTY02230N02230	Skagway Municipality, AK	Skagway Municipality	83600	18200	20800	23400	25950	28050	30150	32200	34300	9999	Skagway Municipality	Alaska	0
AK	0224099999	2	240	NCNTY02240N02240	Southeast Fairbanks Census Area, AK	Southeast Fairbanks Census Area	82700	18200	20800	23400	25950	28050	30150	32200	34300	9999	Southeast Fairbanks Census Area	Alaska	0
AK	0226199999	2	261	NCNTY02261N02261	Valdez-Cordova Census Area, AK	Valdez-Cordova Census Area	113200	23700	27100	30500	33850	36600	39300	42000	44700	9999	Valdez-Cordova Census Area	Alaska	0
AK	0227599999	2	275	NCNTY02275N02275	Wrangell City and Borough, AK	Wrangell City and Borough	71400	18200	20800	23400	25950	28050	30150	32200	34300	9999	Wrangell City and Borough	Alaska	0
AK	0228299999	2	282	NCNTY02282N02282	Yakutat City and Borough, AK	Yakutat City and Borough	90800	19100	21800	24550	27250	29450	31650	33800	36000	9999	Yakutat City and Borough	Alaska	0
AK	0229099999	2	290	NCNTY02290N02290	Yukon-Koyukuk Census Area, AK	Yukon-Koyukuk Census Area	51400	18200	20800	23400	25950	28050	30150	32200	34300	9999	Yukon-Koyukuk Census Area	Alaska	0
AZ	0400199999	4	1	NCNTY04001N04001	Apache County, AZ	Apache County	43200	10400	11850	13350	14800	16000	17200	18400	19550	9999	Apache County	Arizona	0
AZ	0400399999	4	3	METRO43420M43420	Sierra Vista-Douglas, AZ MSA	Cochise County	66300	12600	14400	16200	17950	19400	20850	22300	23700	9999	Cochise County	Arizona	1
AZ	0400599999	4	5	METRO22380M22380	Flagstaff, AZ MSA	Coconino County	75200	15800	18050	20300	22550	24400	26200	28000	29800	2620	Coconino County	Arizona	1
AZ	0400799999	4	7	NCNTY04007N04007	Gila County, AZ	Gila County	51800	11300	12900	14500	16100	17400	18700	20000	21300	9999	Gila County	Arizona	0
AZ	0400999999	4	9	NCNTY04009N04009	Graham County, AZ	Graham County	62400	13100	15000	16850	18700	20200	21700	23200	24700	9999	Graham County	Arizona	0
AZ	0401199999	4	11	NCNTY04011N04011	Greenlee County, AZ	Greenlee County	64600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Greenlee County	Arizona	0
AZ	0401299999	4	12	NCNTY04012N04012	La Paz County, AZ	La Paz County	47300	10500	12000	13500	15000	16200	17400	18600	19800	9999	La Paz County	Arizona	0
AZ	0401399999	4	13	METRO38060M38060	Phoenix-Mesa-Scottsdale, AZ MSA	Maricopa County	77800	16350	18700	21050	23350	25250	27100	29000	30850	6200	Maricopa County	Arizona	1
AZ	0401599999	4	15	METRO29420M29420	Lake Havasu City-Kingman, AZ MSA	Mohave County	55700	11700	13400	15050	16700	18050	19400	20750	22050	4120	Mohave County	Arizona	1
AZ	0401799999	4	17	NCNTY04017N04017	Navajo County, AZ	Navajo County	53200	11200	12800	14400	15950	17250	18550	19800	21100	9999	Navajo County	Arizona	0
AZ	0401999999	4	19	METRO46060M46060	Tucson, AZ MSA	Pima County	68400	14350	16400	18450	20500	22150	23800	25450	27100	8520	Pima County	Arizona	1
AZ	0402199999	4	21	METRO38060M38060	Phoenix-Mesa-Scottsdale, AZ MSA	Pinal County	77800	16350	18700	21050	23350	25250	27100	29000	30850	6200	Pinal County	Arizona	1
AZ	0402399999	4	23	NCNTY04023N04023	Santa Cruz County, AZ	Santa Cruz County	46800	10400	11850	13350	14800	16000	17200	18400	19550	9999	Santa Cruz County	Arizona	0
AZ	0402599999	4	25	METRO39140M39140	Prescott, AZ MSA	Yavapai County	64600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Yavapai County	Arizona	1
AZ	0402799999	4	27	METRO49740M49740	Yuma, AZ MSA	Yuma County	56500	11550	13200	14850	16450	17800	19100	20400	21750	9360	Yuma County	Arizona	1
AR	0500199999	5	1	NCNTY05001N05001	Arkansas County, AR	Arkansas County	51800	11050	12600	14200	15750	17050	18300	19550	20800	9999	Arkansas County	Arkansas	0
AR	0500399999	5	3	NCNTY05003N05003	Ashley County, AR	Ashley County	50800	11050	12600	14200	15750	17050	18300	19550	20800	9999	Ashley County	Arkansas	0
AR	0500599999	5	5	NCNTY05005N05005	Baxter County, AR	Baxter County	51400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Baxter County	Arkansas	0
AR	0500799999	5	7	METRO22220M22220	Fayetteville-Springdale-Rogers, AR HUD Metro FMR Area	Benton County	73600	15500	17700	19900	22100	23900	25650	27450	29200	2580	Benton County	Arkansas	1
AR	0500999999	5	9	NCNTY05009N05009	Boone County, AR	Boone County	49900	11050	12600	14200	15750	17050	18300	19550	20800	9999	Boone County	Arkansas	0
AR	0501199999	5	11	NCNTY05011N05011	Bradley County, AR	Bradley County	49800	11050	12600	14200	15750	17050	18300	19550	20800	9999	Bradley County	Arkansas	0
AR	0501399999	5	13	NCNTY05013N05013	Calhoun County, AR	Calhoun County	50400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Calhoun County	Arkansas	0
AR	0501599999	5	15	NCNTY05015N05015	Carroll County, AR	Carroll County	54700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Carroll County	Arkansas	0
AR	0501799999	5	17	NCNTY05017N05017	Chicot County, AR	Chicot County	41500	11050	12600	14200	15750	17050	18300	19550	20800	9999	Chicot County	Arkansas	0
AR	0501999999	5	19	NCNTY05019N05019	Clark County, AR	Clark County	57700	12150	13850	15600	17300	18700	20100	21500	22850	9999	Clark County	Arkansas	0
AR	0502199999	5	21	NCNTY05021N05021	Clay County, AR	Clay County	45900	11050	12600	14200	15750	17050	18300	19550	20800	9999	Clay County	Arkansas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
AR	0502399999	5	23	NCNTY05023N05023	Cleburne County, AR	Cleburne County	59700	12550	14350	16150	17900	19350	20800	22200	23650	9999	Cleburne County	Arkansas	0
AR	0502599999	5	25	METRO38220M38220	Pine Bluff, AR MSA	Cleveland County	52600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Cleveland County	Arkansas	1
AR	0502799999	5	27	NCNTY05027N05027	Columbia County, AR	Columbia County	52200	11050	12600	14200	15750	17050	18300	19550	20800	9999	Columbia County	Arkansas	0
AR	0502999999	5	29	NCNTY05029N05029	Conway County, AR	Conway County	54600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Conway County	Arkansas	0
AR	0503199999	5	31	METRO27860MM3700	Jonesboro, AR HUD Metro FMR Area	Craighead County	65200	12450	14200	16000	17750	19200	20600	22050	23450	3700	Craighead County	Arkansas	1
AR	0503399999	5	33	METRO22900M22900	Fort Smith, AR-OK HUD Metro FMR Area	Crawford County	54200	11400	13000	14650	16250	17550	18850	20150	21450	2720	Crawford County	Arkansas	1
AR	0503599999	5	35	METRO32820M32820	Memphis, TN-MS-AR HUD Metro FMR Area	Crittenden County	67900	14250	16300	18350	20350	22000	23650	25250	26900	4920	Crittenden County	Arkansas	1
AR	0503799999	5	37	NCNTY05037N05037	Cross County, AR	Cross County	54200	11400	13000	14650	16250	17550	18850	20150	21450	9999	Cross County	Arkansas	0
AR	0503999999	5	39	NCNTY05039N05039	Dallas County, AR	Dallas County	48700	11050	12600	14200	15750	17050	18300	19550	20800	9999	Dallas County	Arkansas	0
AR	0504199999	5	41	NCNTY05041N05041	Desha County, AR	Desha County	40500	11050	12600	14200	15750	17050	18300	19550	20800	9999	Desha County	Arkansas	0
AR	0504399999	5	43	NCNTY05043N05043	Drew County, AR	Drew County	53900	11350	12950	14550	16150	17450	18750	20050	21350	9999	Drew County	Arkansas	0
AR	0504599999	5	45	METRO30780M30780	Little Rock-North Little Rock-Conway, AR HUD Metro FMR Area	Faulkner County	72200	15200	17350	19500	21650	23400	25150	26850	28600	4400	Faulkner County	Arkansas	1
AR	0504799999	5	47	NCNTY05047N05047	Franklin County, AR	Franklin County	49100	11050	12600	14200	15750	17050	18300	19550	20800	9999	Franklin County	Arkansas	0
AR	0504999999	5	49	NCNTY05049N05049	Fulton County, AR	Fulton County	45300	11050	12600	14200	15750	17050	18300	19550	20800	9999	Fulton County	Arkansas	0
AR	0505199999	5	51	METRO26300M26300	Hot Springs, AR MSA	Garland County	63900	13150	15000	16900	18750	20250	21750	23250	24750	9999	Garland County	Arkansas	1
AR	0505399999	5	53	METRO30780N05053	Grant County, AR HUD Metro FMR Area	Grant County	64700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Grant County	Arkansas	1
AR	0505599999	5	55	NCNTY05055N05055	Greene County, AR	Greene County	58700	12350	14100	15850	17600	19050	20450	21850	23250	9999	Greene County	Arkansas	0
AR	0505799999	5	57	NCNTY05057N05057	Hempstead County, AR	Hempstead County	51200	11050	12600	14200	15750	17050	18300	19550	20800	9999	Hempstead County	Arkansas	0
AR	0505999999	5	59	NCNTY05059N05059	Hot Spring County, AR	Hot Spring County	55300	11650	13300	14950	16600	17950	19300	20600	21950	9999	Hot Spring County	Arkansas	0
AR	0506199999	5	61	NCNTY05061N05061	Howard County, AR	Howard County	47400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Howard County	Arkansas	0
AR	0506399999	5	63	NCNTY05063N05063	Independence County, AR	Independence County	54800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Independence County	Arkansas	0
AR	0506599999	5	65	NCNTY05065N05065	Izard County, AR	Izard County	52000	11050	12600	14200	15750	17050	18300	19550	20800	9999	Izard County	Arkansas	0
AR	0506799999	5	67	NCNTY05067N05067	Jackson County, AR	Jackson County	44900	11050	12600	14200	15750	17050	18300	19550	20800	9999	Jackson County	Arkansas	0
AR	0506999999	5	69	METRO38220M38220	Pine Bluff, AR MSA	Jefferson County	52600	11100	12650	14250	15800	17100	18350	19600	20900	6240	Jefferson County	Arkansas	1
AR	0507199999	5	71	NCNTY05071N05071	Johnson County, AR	Johnson County	45600	11050	12600	14200	15750	17050	18300	19550	20800	9999	Johnson County	Arkansas	0
AR	0507399999	5	73	NCNTY05073N05073	Lafayette County, AR	Lafayette County	46300	11050	12600	14200	15750	17050	18300	19550	20800	9999	Lafayette County	Arkansas	0
AR	0507599999	5	75	NCNTY05075N05075	Lawrence County, AR	Lawrence County	51400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Lawrence County	Arkansas	0
AR	0507799999	5	77	NCNTY05077N05077	Lee County, AR	Lee County	41900	11050	12600	14200	15750	17050	18300	19550	20800	9999	Lee County	Arkansas	0
AR	0507999999	5	79	METRO38220M38220	Pine Bluff, AR MSA	Lincoln County	52600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Lincoln County	Arkansas	1
AR	0508199999	5	81	METRO45500N05081	Little River County, AR HUD Metro FMR Area	Little River County	54500	11450	13100	14750	16350	17700	19000	20300	21600	9999	Little River County	Arkansas	1
AR	0508399999	5	83	NCNTY05083N05083	Logan County, AR	Logan County	48900	11050	12600	14200	15750	17050	18300	19550	20800	9999	Logan County	Arkansas	0
AR	0508599999	5	85	METRO30780M30780	Little Rock-North Little Rock-Conway, AR HUD Metro FMR Area	Lonoke County	72200	15200	17350	19500	21650	23400	25150	26850	28600	4400	Lonoke County	Arkansas	1
AR	0508799999	5	87	METRO22220M22220	Fayetteville-Springdale-Rogers, AR HUD Metro FMR Area	Madison County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Madison County	Arkansas	1
AR	0508999999	5	89	NCNTY05089N05089	Marion County, AR	Marion County	46400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Marion County	Arkansas	0
AR	0509199999	5	91	METRO45500M45500	Texarkana, TX-Texarkana, AR HUD Metro FMR Area	Miller County	69800	13300	15200	17100	19000	20550	22050	23600	25100	8360	Miller County	Arkansas	1
AR	0509399999	5	93	NCNTY05093N05093	Mississippi County, AR	Mississippi County	44700	11050	12600	14200	15750	17050	18300	19550	20800	9999	Mississippi County	Arkansas	0
AR	0509599999	5	95	NCNTY05095N05095	Monroe County, AR	Monroe County	47400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Monroe County	Arkansas	0
AR	0509799999	5	97	NCNTY05097N05097	Montgomery County, AR	Montgomery County	48900	11050	12600	14200	15750	17050	18300	19550	20800	9999	Montgomery County	Arkansas	0
AR	0509999999	5	99	NCNTY05099N05099	Nevada County, AR	Nevada County	50500	11050	12600	14200	15750	17050	18300	19550	20800	9999	Nevada County	Arkansas	0
AR	0510199999	5	101	NCNTY05101N05101	Newton County, AR	Newton County	50200	11050	12600	14200	15750	17050	18300	19550	20800	9999	Newton County	Arkansas	0
AR	0510399999	5	103	NCNTY05103N05103	Ouachita County, AR	Ouachita County	45400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Ouachita County	Arkansas	0
AR	0510599999	5	105	METRO30780M30780	Little Rock-North Little Rock-Conway, AR HUD Metro FMR Area	Perry County	72200	15200	17350	19500	21650	23400	25150	26850	28600	9999	Perry County	Arkansas	1

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AR	0510799999	5	107	NCNTY05107N05107	Phillips County, AR	Phillips County	37100	11050	12600	14200	15750	17050	18300	19550	20800	9999	Phillips County	Arkansas	0
AR	0510999999	5	109	NCNTY05109N05109	Pike County, AR	Pike County	51800	11050	12600	14200	15750	17050	18300	19550	20800	9999	Pike County	Arkansas	0
AR	0511199999	5	111	METRO27860N05111	Poinsett County, AR HUD Metro FMR Area	Poinsett County	46600	11050	12600	14200	15750	17050	18300	19550	20800	9999	Poinsett County	Arkansas	1
AR	0511399999	5	113	NCNTY05113N05113	Polk County, AR	Polk County	42600	11050	12600	14200	15750	17050	18300	19550	20800	9999	Polk County	Arkansas	0
AR	0511599999	5	115	NCNTY05115N05115	Pope County, AR	Pope County	54100	11400	13000	14650	16250	17550	18850	20150	21450	9999	Pope County	Arkansas	0
AR	0511799999	5	117	NCNTY05117N05117	Prairie County, AR	Prairie County	51000	11050	12600	14200	15750	17050	18300	19550	20800	9999	Prairie County	Arkansas	0
AR	0511999999	5	119	METRO30780M30780	Little Rock-North Little Rock-Conway, AR HUD Metro FMR Area	Pulaski County	72200	15200	17350	19500	21650	23400	25150	26850	28600	4400	Pulaski County	Arkansas	1
AR	0512199999	5	121	NCNTY05121N05121	Randolph County, AR	Randolph County	48400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Randolph County	Arkansas	0
AR	0512399999	5	123	NCNTY05123N05123	St. Francis County, AR	St. Francis County	43200	11050	12600	14200	15750	17050	18300	19550	20800	9999	St. Francis County	Arkansas	0
AR	0512599999	5	125	METRO30780M30780	Little Rock-North Little Rock-Conway, AR HUD Metro FMR Area	Saline County	72200	15200	17350	19500	21650	23400	25150	26850	28600	4400	Saline County	Arkansas	1
AR	0512799999	5	127	NCNTY05127N05127	Scott County, AR	Scott County	45400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Scott County	Arkansas	0
AR	0512999999	5	129	NCNTY05129N05129	Searcy County, AR	Searcy County	46900	11050	12600	14200	15750	17050	18300	19550	20800	9999	Searcy County	Arkansas	0
AR	0513199999	5	131	METRO22900M22900	Fort Smith, AR-OK HUD Metro FMR Area	Sebastian County	54200	11400	13000	14650	16250	17550	18850	20150	21450	2720	Sebastian County	Arkansas	1
AR	0513399999	5	133	NCNTY05133N05133	Sevier County, AR	Sevier County	56000	11800	13450	15150	16800	18150	19500	20850	22200	9999	Sevier County	Arkansas	0
AR	0513599999	5	135	NCNTY05135N05135	Sharp County, AR	Sharp County	43200	11050	12600	14200	15750	17050	18300	19550	20800	9999	Sharp County	Arkansas	0
AR	0513799999	5	137	NCNTY05137N05137	Stone County, AR	Stone County	44300	11050	12600	14200	15750	17050	18300	19550	20800	9999	Stone County	Arkansas	0
AR	0513999999	5	139	NCNTY05139N05139	Union County, AR	Union County	55100	11600	13250	14900	16550	17900	19200	20550	21850	9999	Union County	Arkansas	0
AR	0514199999	5	141	NCNTY05141N05141	Van Buren County, AR	Van Buren County	46400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Van Buren County	Arkansas	0
AR	0514399999	5	143	METRO22220M22220	Fayetteville-Springdale-Rogers, AR HUD Metro FMR Area	Washington County	73600	15500	17700	19900	22100	23900	25650	27450	29200	2580	Washington County	Arkansas	1
AR	0514599999	5	145	NCNTY05145N05145	White County, AR	White County	57200	12050	13750	15450	17150	18550	19900	21300	22650	9999	White County	Arkansas	0
AR	0514799999	5	147	NCNTY05147N05147	Woodruff County, AR	Woodruff County	49400	11050	12600	14200	15750	17050	18300	19550	20800	9999	Woodruff County	Arkansas	0
AR	0514999999	5	149	NCNTY05149N05149	Yell County, AR	Yell County	48700	11050	12600	14200	15750	17050	18300	19550	20800	9999	Yell County	Arkansas	0
CA	0600199999	6	1	METRO41860MM5775	Oakland-Fremont, CA HUD Metro FMR Area	Alameda County	119200	27450	31350	35250	39150	42300	45450	48550	51700	5775	Alameda County	California	1
CA	0600399999	6	3	NCNTY06003N06003	Alpine County, CA	Alpine County	83200	17500	20000	22500	24950	26950	28950	30950	32950	9999	Alpine County	California	0
CA	0600599999	6	5	NCNTY06005N06005	Amador County, CA	Amador County	78700	16550	18900	21250	23600	25500	27400	29300	31200	9999	Amador County	California	0
CA	0600799999	6	7	METRO17020M17020	Chico, CA MSA	Butte County	66100	14850	17000	19100	21200	22900	24600	26300	28000	1620	Butte County	California	1
CA	0600999999	6	9	NCNTY06009N06009	Calaveras County, CA	Calaveras County	80400	16900	19300	21700	24100	26050	28000	29900	31850	9999	Calaveras County	California	0
CA	0601199999	6	11	NCNTY06011N06011	Colusa County, CA	Colusa County	66400	14700	16800	18900	20950	22650	24350	26000	27700	9999	Colusa County	California	0
CA	0601399999	6	13	METRO41860MM5775	Oakland-Fremont, CA HUD Metro FMR Area	Contra Costa County	119200	27450	31350	35250	39150	42300	45450	48550	51700	5775	Contra Costa County	California	1
CA	0601599999	6	15	NCNTY06015N06015	Del Norte County, CA	Del Norte County	57400	14700	16800	18900	20950	22650	24350	26000	27700	9999	Del Norte County	California	0
CA	0601799999	6	17	METRO40900M40900	Sacramento--Roseville--Arden-Arcade, CA HUD Metro FMR Area	El Dorado County	86300	18150	20750	23350	25900	28000	30050	32150	34200	6920	El Dorado County	California	1
CA	0601999999	6	19	METRO23420M23420	Fresno, CA MSA	Fresno County	61700	14700	16800	18900	20950	22650	24350	26000	27700	2840	Fresno County	California	1
CA	0602199999	6	21	NCNTY06021N06021	Glenn County, CA	Glenn County	56700	14700	16800	18900	20950	22650	24350	26000	27700	9999	Glenn County	California	0
CA	0602399999	6	23	NCNTY06023N06023	Humboldt County, CA	Humboldt County	72000	14700	16800	18900	20950	22650	24350	26000	27700	9999	Humboldt County	California	0
CA	0602599999	6	25	METRO20940M20940	El Centro, CA MSA	Imperial County	55600	14700	16800	18900	20950	22650	24350	26000	27700	9999	Imperial County	California	1
CA	0602799999	6	27	NCNTY06027N06027	Inyo County, CA	Inyo County	75100	15800	18050	20300	22550	24400	26200	28000	29800	9999	Inyo County	California	0
CA	0602999999	6	29	METRO12540M12540	Bakersfield, CA MSA	Kern County	56600	14700	16800	18900	20950	22650	24350	26000	27700	680	Kern County	California	1
CA	0603199999	6	31	METRO25260M25260	Hanford-Corcoran, CA MSA	Kings County	62200	14700	16800	18900	20950	22650	24350	26000	27700	9999	Kings County	California	1
CA	0603399999	6	33	NCNTY06033N06033	Lake County, CA	Lake County	65800	14700	16800	18900	20950	22650	24350	26000	27700	9999	Lake County	California	0
CA	0603599999	6	35	NCNTY06035N06035	Lassen County, CA	Lassen County	70400	14850	17000	19100	21200	22900	24600	26300	28000	9999	Lassen County	California	0
CA	0603799999	6	37	METRO31080MM4480	Los Angeles-Long Beach-Glendale, CA HUD Metro FMR Area	Los Angeles County	77300	23700	27050	30450	33800	36550	39250	41950	44650	4480	Los Angeles County	California	1
CA	0603999999	6	39	METRO31460M31460	Madera, CA MSA	Madera County	59400	14700	16800	18900	20950	22650	24350	26000	27700	2840	Madera County	California	1
CA	0604199999	6	41	METRO41860MM7360	San Francisco, CA HUD Metro FMR Area	Marin County	143100	36550	41800	47000	52200	56400	60600	64750	68950	7360	Marin County	California	1

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CA	0604399999	6	43	NCNTY06043N06043	Mariposa County, CA	Mariposa County	66900	14700	16800	18900	20950	22650	24350	26000	27700	9999	Mariposa County	California	0
CA	0604599999	6	45	NCNTY06045N06045	Mendocino County, CA	Mendocino County	70700	14700	16800	18900	20950	22650	24350	26000	27700	9999	Mendocino County	California	0
CA	0604799999	6	47	METRO32900M32900	Merced, CA MSA	Merced County	52300	14700	16800	18900	20950	22650	24350	26000	27700	4940	Merced County	California	1
CA	0604999999	6	49	NCNTY06049N06049	Modoc County, CA	Modoc County	54200	14700	16800	18900	20950	22650	24350	26000	27700	9999	Modoc County	California	0
CA	0605199999	6	51	NCNTY06051N06051	Mono County, CA	Mono County	80900	17000	19400	21850	24250	26200	28150	30100	32050	9999	Mono County	California	0
CA	0605399999	6	53	METRO41500M41500	Salinas, CA MSA	Monterey County	81600	20350	23250	26150	29050	31400	33700	36050	38350	7120	Monterey County	California	1
CA	0605599999	6	55	METRO34900M34900	Napa, CA MSA	Napa County	109200	22750	26000	29250	32500	35100	37700	40300	42900	8720	Napa County	California	1
CA	0605799999	6	57	NCNTY06057N06057	Nevada County, CA	Nevada County	92400	18100	20650	23250	25800	27900	29950	32000	34100	9999	Nevada County	California	0
CA	0605999999	6	59	METRO31080MM5945	Santa Ana-Anaheim-Irvine, CA HUD Metro FMR Area	Orange County	103000	26950	30800	34650	38450	41550	44650	47700	50800	5945	Orange County	California	1
CA	0606199999	6	61	METRO40900M40900	Sacramento--Roseville--Arden-Arcade, CA HUD Metro FMR Area	Placer County	86300	18150	20750	23350	25900	28000	30050	32150	34200	6920	Placer County	California	1
CA	0606399999	6	63	NCNTY06063N06063	Plumas County, CA	Plumas County	72200	15200	17350	19500	21650	23400	25150	26850	28600	9999	Plumas County	California	0
CA	0606599999	6	65	METRO40140M40140	Riverside-San Bernardino-Ontario, CA MSA	Riverside County	75300	15850	18100	20350	22600	24450	26250	28050	29850	6780	Riverside County	California	1
CA	0606799999	6	67	METRO40900M40900	Sacramento--Roseville--Arden-Arcade, CA HUD Metro FMR Area	Sacramento County	86300	18150	20750	23350	25900	28000	30050	32150	34200	6920	Sacramento County	California	1
CA	0606999999	6	69	METRO41940N06069	San Benito County, CA HUD Metro FMR Area	San Benito County	89700	20950	23950	26950	29900	32300	34700	37100	39500	9999	San Benito County	California	1
CA	0607199999	6	71	METRO40140M40140	Riverside-San Bernardino-Ontario, CA MSA	San Bernardino County	75300	15850	18100	20350	22600	24450	26250	28050	29850	6780	San Bernardino County	California	1
CA	0607399999	6	73	METRO41740M41740	San Diego-Carlsbad, CA MSA	San Diego County	92700	24300	27750	31200	34650	37450	40200	43000	45750	7320	San Diego County	California	1
CA	0607599999	6	75	METRO41860MM7360	San Francisco, CA HUD Metro FMR Area	San Francisco County	143100	36550	41800	47000	52200	56400	60600	64750	68950	7360	San Francisco County	California	1
CA	0607799999	6	77	METRO44700M44700	Stockton-Lodi, CA MSA	San Joaquin County	75000	15750	18000	20250	22500	24300	26100	27900	29700	8120	San Joaquin County	California	1
CA	0607999999	6	79	METRO42020M42020	San Luis Obispo-Paso Robles-Arroyo Grande, CA MSA	San Luis Obispo County	97300	20400	23300	26200	29100	31450	33800	36100	38450	7460	San Luis Obispo County	California	1
CA	0608199999	6	81	METRO41860MM7360	San Francisco, CA HUD Metro FMR Area	San Mateo County	143100	36550	41800	47000	52200	56400	60600	64750	68950	7360	San Mateo County	California	1
CA	0608399999	6	83	METRO42200M42200	Santa Maria-Santa Barbara, CA MSA	Santa Barbara County	87800	25000	28600	32150	35700	38600	41450	44300	47150	7480	Santa Barbara County	California	1
CA	0608599999	6	85	METRO41940M41940	San Jose-Sunnyvale-Santa Clara, CA HUD Metro FMR Area	Santa Clara County	141600	33150	37900	42650	47350	51150	54950	58750	62550	7400	Santa Clara County	California	1
CA	0608799999	6	87	METRO42100M42100	Santa Cruz-Watsonville, CA MSA	Santa Cruz County	110000	27800	31800	35750	39700	42900	46100	49250	52450	7485	Santa Cruz County	California	1
CA	0608999999	6	89	METRO39820M39820	Redding, CA MSA	Shasta County	68500	14700	16800	18900	20950	22650	24350	26000	27700	6690	Shasta County	California	1
CA	0609199999	6	91	NCNTY06091N06091	Sierra County, CA	Sierra County	80500	16950	19350	21750	24150	26100	28050	29950	31900	9999	Sierra County	California	0
CA	0609399999	6	93	NCNTY06093N06093	Siskiyou County, CA	Siskiyou County	54400	14700	16800	18900	20950	22650	24350	26000	27700	9999	Siskiyou County	California	0
CA	0609599999	6	95	METRO46700M46700	Vallejo-Fairfield, CA MSA	Solano County	95400	19450	22200	25000	27750	30000	32200	34450	36650	8720	Solano County	California	1
CA	0609799999	6	97	METRO42220M42220	Santa Rosa, CA MSA	Sonoma County	102700	23900	27300	30700	34100	36850	39600	42300	45050	7500	Sonoma County	California	1
CA	0609999999	6	99	METRO33700M33700	Modesto, CA MSA	Stanislaus County	69300	14700	16800	18900	20950	22650	24350	26000	27700	5170	Stanislaus County	California	1
CA	0610199999	6	101	METRO49700M49700	Yuba City, CA MSA	Sutter County	75000	14700	16800	18900	20950	22650	24350	26000	27700	9340	Sutter County	California	1
CA	0610399999	6	103	NCNTY06103N06103	Tehama County, CA	Tehama County	55800	14700	16800	18900	20950	22650	24350	26000	27700	9999	Tehama County	California	0
CA	0610599999	6	105	NCNTY06105N06105	Trinity County, CA	Trinity County	51600	14700	16800	18900	20950	22650	24350	26000	27700	9999	Trinity County	California	0
CA	0610799999	6	107	METRO47300M47300	Visalia-Porterville, CA MSA	Tulare County	52900	14700	16800	18900	20950	22650	24350	26000	27700	8780	Tulare County	California	1
CA	0610999999	6	109	NCNTY06109N06109	Tuolumne County, CA	Tuolumne County	71600	14900	17000	19150	21250	22950	24650	26350	28050	9999	Tuolumne County	California	0
CA	0611199999	6	111	METRO37100M37100	Oxnard-Thousand Oaks-Ventura, CA MSA	Ventura County	97800	23700	27100	30500	33850	36600	39300	42000	44700	8735	Ventura County	California	1
CA	0611399999	6	113	METRO40900MM9270	Yolo, CA HUD Metro FMR Area	Yolo County	92500	19450	22200	25000	27750	30000	32200	34450	36650	9270	Yolo County	California	1
CA	0611599999	6	115	METRO49700M49700	Yuba City, CA MSA	Yuba County	75000	14700	16800	18900	20950	22650	24350	26000	27700	9340	Yuba County	California	1
CO	0800199999	8	1	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Adams County	100000	21000	24000	27000	30000	32400	34800	37200	39600	2080	Adams County	Colorado	1
CO	0800399999	8	3	NCNTY08003N08003	Alamosa County, CO	Alamosa County	49100	14950	17050	19200	21300	23050	24750	26450	28150	9999	Alamosa County	Colorado	0
CO	0800599999	8	5	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Arapahoe County	100000	21000	24000	27000	30000	32400	34800	37200	39600	2080	Arapahoe County	Colorado	1
CO	0800799999	8	7	NCNTY08007N08007	Archuleta County, CO	Archuleta County	58400	14950	17050	19200	21300	23050	24750	26450	28150	9999	Archuleta County	Colorado	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
CO	0800999999	8	9	NCNTY08009N08009	Baca County, CO	Baca County	48800	14950	17050	19200	21300	23050	24750	26450	28150	9999	Baca County	Colorado	0
CO	0801199999	8	11	NCNTY08011N08011	Bent County, CO	Bent County	43400	14950	17050	19200	21300	23050	24750	26450	28150	9999	Bent County	Colorado	0
CO	0801399999	8	13	METRO14500M14500	Boulder, CO MSA	Boulder County	115100	24200	27650	31100	34550	37350	40100	42850	45650	1125	Boulder County	Colorado	1
CO	0801499999	8	14	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Broomfield County	100000	21000	24000	27000	30000	32400	34800	37200	39600	2080	Broomfield County	Colorado	1
CO	0801599999	8	15	NCNTY08015N08015	Chaffee County, CO	Chaffee County	71300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Chaffee County	Colorado	0
CO	0801799999	8	17	NCNTY08017N08017	Cheyenne County, CO	Cheyenne County	72800	15300	17500	19700	21850	23600	25350	27100	28850	9999	Cheyenne County	Colorado	0
CO	0801999999	8	19	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Clear Creek County	100000	21000	24000	27000	30000	32400	34800	37200	39600	9999	Clear Creek County	Colorado	1
CO	0802199999	8	21	NCNTY08021N08021	Conejos County, CO	Conejos County	53200	14950	17050	19200	21300	23050	24750	26450	28150	9999	Conejos County	Colorado	0
CO	0802399999	8	23	NCNTY08023N08023	Costilla County, CO	Costilla County	36800	14950	17050	19200	21300	23050	24750	26450	28150	9999	Costilla County	Colorado	0
CO	0802599999	8	25	NCNTY08025N08025	Crowley County, CO	Crowley County	52900	14950	17050	19200	21300	23050	24750	26450	28150	9999	Crowley County	Colorado	0
CO	0802799999	8	27	NCNTY08027N08027	Custer County, CO	Custer County	57700	14950	17050	19200	21300	23050	24750	26450	28150	9999	Custer County	Colorado	0
CO	0802999999	8	29	NCNTY08029N08029	Delta County, CO	Delta County	58100	14950	17050	19200	21300	23050	24750	26450	28150	9999	Delta County	Colorado	0
CO	0803199999	8	31	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Denver County	100000	21000	24000	27000	30000	32400	34800	37200	39600	2080	Denver County	Colorado	1
CO	0803399999	8	33	NCNTY08033N08033	Dolores County, CO	Dolores County	51400	14950	17050	19200	21300	23050	24750	26450	28150	9999	Dolores County	Colorado	0
CO	0803599999	8	35	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Douglas County	100000	21000	24000	27000	30000	32400	34800	37200	39600	2080	Douglas County	Colorado	1
CO	0803799999	8	37	NCNTY08037N08037	Eagle County, CO	Eagle County	99900	21000	24000	27000	29950	32350	34750	37150	39550	9999	Eagle County	Colorado	0
CO	0803999999	8	39	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Elbert County	100000	21000	24000	27000	30000	32400	34800	37200	39600	9999	Elbert County	Colorado	1
CO	0804199999	8	41	METRO17820M17820	Colorado Springs, CO HUD Metro FMR Area	El Paso County	81600	17150	19600	22050	24500	26500	28450	30400	32350	1720	El Paso County	Colorado	1
CO	0804399999	8	43	NCNTY08043N08043	Fremont County, CO	Fremont County	59500	14950	17050	19200	21300	23050	24750	26450	28150	9999	Fremont County	Colorado	0
CO	0804599999	8	45	NCNTY08045N08045	Garfield County, CO	Garfield County	84500	17750	20300	22850	25350	27400	29450	31450	33500	9999	Garfield County	Colorado	0
CO	0804799999	8	47	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Gilpin County	100000	21000	24000	27000	30000	32400	34800	37200	39600	9999	Gilpin County	Colorado	1
CO	0804999999	8	49	NCNTY08049N08049	Grand County, CO	Grand County	78800	16600	18950	21300	23650	25550	27450	29350	31250	9999	Grand County	Colorado	0
CO	0805199999	8	51	NCNTY08051N08051	Gunnison County, CO	Gunnison County	75400	15850	18100	20350	22600	24450	26250	28050	29850	9999	Gunnison County	Colorado	0
CO	0805399999	8	53	NCNTY08053N08053	Hinsdale County, CO	Hinsdale County	76700	16100	18400	20700	23000	24850	26700	28550	30400	9999	Hinsdale County	Colorado	0
CO	0805599999	8	55	NCNTY08055N08055	Huerfano County, CO	Huerfano County	52600	14950	17050	19200	21300	23050	24750	26450	28150	9999	Huerfano County	Colorado	0
CO	0805799999	8	57	NCNTY08057N08057	Jackson County, CO	Jackson County	63900	14950	17050	19200	21300	23050	24750	26450	28150	9999	Jackson County	Colorado	0
CO	0805999999	8	59	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Jefferson County	100000	21000	24000	27000	30000	32400	34800	37200	39600	2080	Jefferson County	Colorado	1
CO	0806199999	8	61	NCNTY08061N08061	Kiowa County, CO	Kiowa County	53500	14950	17050	19200	21300	23050	24750	26450	28150	9999	Kiowa County	Colorado	0
CO	0806399999	8	63	NCNTY08063N08063	Kit Carson County, CO	Kit Carson County	60400	14950	17050	19200	21300	23050	24750	26450	28150	9999	Kit Carson County	Colorado	0
CO	0806599999	8	65	NCNTY08065N08065	Lake County, CO	Lake County	66800	14950	17050	19200	21300	23050	24750	26450	28150	9999	Lake County	Colorado	0
CO	0806799999	8	67	NCNTY08067N08067	La Plata County, CO	La Plata County	83600	17600	20100	22600	25100	27150	29150	31150	33150	9999	La Plata County	Colorado	0
CO	0806999999	8	69	METRO22660M22660	Fort Collins, CO MSA	Larimer County	99400	19800	22600	25450	28250	30550	32800	35050	37300	2670	Larimer County	Colorado	1
CO	0807199999	8	71	NCNTY08071N08071	Las Animas County, CO	Las Animas County	56200	14950	17050	19200	21300	23050	24750	26450	28150	9999	Las Animas County	Colorado	0
CO	0807399999	8	73	NCNTY08073N08073	Lincoln County, CO	Lincoln County	64000	14950	17050	19200	21300	23050	24750	26450	28150	9999	Lincoln County	Colorado	0
CO	0807599999	8	75	NCNTY08075N08075	Logan County, CO	Logan County	60800	14950	17050	19200	21300	23050	24750	26450	28150	9999	Logan County	Colorado	0
CO	0807799999	8	77	METRO24300M24300	Grand Junction, CO MSA	Mesa County	67700	14950	17050	19200	21300	23050	24750	26450	28150	2995	Mesa County	Colorado	1
CO	0807999999	8	79	NCNTY08079N08079	Mineral County, CO	Mineral County	75500	15900	18150	20400	22650	24500	26300	28100	29900	9999	Mineral County	Colorado	0
CO	0808199999	8	81	NCNTY08081N08081	Moffat County, CO	Moffat County	72700	15300	17450	19650	21800	23550	25300	27050	28800	9999	Moffat County	Colorado	0
CO	0808399999	8	83	NCNTY08083N08083	Montezuma County, CO	Montezuma County	59200	14950	17050	19200	21300	23050	24750	26450	28150	9999	Montezuma County	Colorado	0
CO	0808599999	8	85	NCNTY08085N08085	Montrose County, CO	Montrose County	60900	14950	17050	19200	21300	23050	24750	26450	28150	9999	Montrose County	Colorado	0
CO	0808799999	8	87	NCNTY08087N08087	Morgan County, CO	Morgan County	61000	14950	17050	19200	21300	23050	24750	26450	28150	9999	Morgan County	Colorado	0
CO	0808999999	8	89	NCNTY08089N08089	Otero County, CO	Otero County	48400	14950	17050	19200	21300	23050	24750	26450	28150	9999	Otero County	Colorado	0
CO	0809199999	8	91	NCNTY08091N08091	Ouray County, CO	Ouray County	76300	16050	18350	20650	22900	24750	26600	28400	30250	9999	Ouray County	Colorado	0
CO	0809399999	8	93	METRO19740M19740	Denver-Aurora-Lakewood, CO MSA	Park County	100000	21000	24000	27000	30000	32400	34800	37200	39600	9999	Park County	Colorado	1
CO	0809599999	8	95	NCNTY08095N08095	Phillips County, CO	Phillips County	68200	14950	17050	19200	21300	23050	24750	26450	28150	9999	Phillips County	Colorado	0
CO	0809799999	8	97	NCNTY08097N08097	Pitkin County, CO	Pitkin County	110500	23250	26550	29850	33150	35850	38500	41150	43800	9999	Pitkin County	Colorado	0
CO	0809999999	8	99	NCNTY08099N08099	Prowers County, CO	Prowers County	53400	14950	17050	19200	21300	23050	24750	26450	28150	9999	Prowers County	Colorado	0
CO	0810199999	8	101	METRO39380M39380	Pueblo, CO MSA	Pueblo County	61200	14950	17050	19200	21300	23050	24750	26450	28150	6560	Pueblo County	Colorado	1
CO	0810399999	8	103	NCNTY08103N08103	Rio Blanco County, CO	Rio Blanco County	83400	17500	20000	22500	25000	27000	29000	31000	33000	9999	Rio Blanco County	Colorado	0
CO	0810599999	8	105	NCNTY08105N08105	Rio Grande County, CO	Rio Grande County	55800	14950	17050	19200	21300	23050	24750	26450	28150	9999	Rio Grande County	Colorado	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
CO	0810799999	8	107	NCNTY08107N08107	Routt County, CO	Routt County	87200	18350	20950	23550	26150	28250	30350	32450	34550	9999	Routt County	Colorado	0
CO	0810999999	8	109	NCNTY08109N08109	Saguache County, CO	Saguache County	48200	14950	17050	19200	21300	23050	24750	26450	28150	9999	Saguache County	Colorado	0
CO	0811199999	8	111	NCNTY08111N08111	San Juan County, CO	San Juan County	64600	14950	17050	19200	21300	23050	24750	26450	28150	9999	San Juan County	Colorado	0
CO	0811399999	8	113	NCNTY08113N08113	San Miguel County, CO	San Miguel County	81500	17150	19600	22050	24450	26450	28400	30350	32300	9999	San Miguel County	Colorado	0
CO	0811599999	8	115	NCNTY08115N08115	Sedgwick County, CO	Sedgwick County	63800	14950	17050	19200	21300	23050	24750	26450	28150	9999	Sedgwick County	Colorado	0
CO	0811799999	8	117	NCNTY08117N08117	Summit County, CO	Summit County	95900	20150	23000	25900	28750	31050	33350	35650	37950	9999	Summit County	Colorado	0
CO	0811999999	8	119	METRO17820N08119	Teller County, CO HUD Metro FMR Area	Teller County	81800	17200	19650	22100	24550	26550	28500	30450	32450	9999	Teller County	Colorado	1
CO	0812199999	8	121	NCNTY08121N08121	Washington County, CO	Washington County	64200	14950	17050	19200	21300	23050	24750	26450	28150	9999	Washington County	Colorado	0
CO	0812399999	8	123	METRO24540M24540	Greeley, CO MSA	Weld County	84300	17750	20250	22800	25300	27350	29350	31400	33400	3060	Weld County	Colorado	1
CO	0812599999	8	125	NCNTY08125N08125	Yuma County, CO	Yuma County	54100	14950	17050	19200	21300	23050	24750	26450	28150	9999	Yuma County	Colorado	0
CT	0900104720	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	Bethel town	Connecticut	1
CT	0900108070	9	1	METRO14860MM1160	Bridgeport, CT HUD Metro FMR Area	Fairfield County	98000	21600	24650	27750	30800	33300	35750	38200	40700	1160	Bridgeport town	Connecticut	1
CT	0900108980	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	Brookfield town	Connecticut	1
CT	0900118500	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	Danbury town	Connecticut	1
CT	0900118850	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	Darien town	Connecticut	1
CT	0900123890	9	1	METRO14860MM1160	Bridgeport, CT HUD Metro FMR Area	Fairfield County	98000	21600	24650	27750	30800	33300	35750	38200	40700	1160	Easton town	Connecticut	1
CT	0900126620	9	1	METRO14860MM1160	Bridgeport, CT HUD Metro FMR Area	Fairfield County	98000	21600	24650	27750	30800	33300	35750	38200	40700	1160	Fairfield town	Connecticut	1
CT	0900133620	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	Greenwich town	Connecticut	1
CT	0900148620	9	1	METRO14860MM1160	Bridgeport, CT HUD Metro FMR Area	Fairfield County	98000	21600	24650	27750	30800	33300	35750	38200	40700	1160	Monroe town	Connecticut	1
CT	0900150580	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	New Canaan town	Connecticut	1
CT	0900150860	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	New Fairfield town	Connecticut	1
CT	0900152980	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	Newtown town	Connecticut	1
CT	0900156060	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	Norwalk town	Connecticut	1
CT	0900163480	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	Redding town	Connecticut	1
CT	0900163970	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	Ridgefield town	Connecticut	1
CT	0900168170	9	1	METRO14860MM1160	Bridgeport, CT HUD Metro FMR Area	Fairfield County	98000	21600	24650	27750	30800	33300	35750	38200	40700	1160	Shelton town	Connecticut	1
CT	0900168310	9	1	METRO14860MM1930	Danbury, CT HUD Metro FMR Area	Fairfield County	122000	25650	29300	32950	36600	39550	42500	45400	48350	1930	Sherman town	Connecticut	1
CT	0900173070	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	Stamford town	Connecticut	1
CT	0900174190	9	1	METRO14860MM1160	Bridgeport, CT HUD Metro FMR Area	Fairfield County	98000	21600	24650	27750	30800	33300	35750	38200	40700	1160	Stratford town	Connecticut	1
CT	0900177200	9	1	METRO14860MM1160	Bridgeport, CT HUD Metro FMR Area	Fairfield County	98000	21600	24650	27750	30800	33300	35750	38200	40700	1160	Trumbull town	Connecticut	1
CT	0900183430	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	Weston town	Connecticut	1
CT	0900183500	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	Westport town	Connecticut	1
CT	0900186370	9	1	METRO14860MM8040	Stamford-Norwalk, CT HUD Metro FMR Area	Fairfield County	143400	30100	34400	38700	43000	46450	49900	53350	56800	8040	Wilton town	Connecticut	1
CT	0900302060	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Avon town	Connecticut	1
CT	0900304300	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Berlin town	Connecticut	1
CT	0900305910	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Bloomfield town	Connecticut	1
CT	0900308490	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Bristol town	Connecticut	1
CT	0900310100	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Burlington town	Connecticut	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
CT	0900312270	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Canton town	Connecticut	1
CT	0900322070	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	East Granby town	Connecticut	1
CT	0900322630	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	East Hartford town	Connecticut	1
CT	0900324800	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	East Windsor town	Connecticut	1
CT	0900325990	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Enfield town	Connecticut	1
CT	0900327600	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Farmington town	Connecticut	1
CT	0900331240	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Glastonbury town	Connecticut	1
CT	0900332640	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Granby town	Connecticut	1
CT	0900337070	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Hartford town	Connecticut	1
CT	0900337140	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	9999	Hartland town	Connecticut	1
CT	0900344700	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Manchester town	Connecticut	1
CT	0900345820	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Marlborough town	Connecticut	1
CT	0900350440	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	New Britain town	Connecticut	1
CT	0900352140	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Newington town	Connecticut	1
CT	0900360120	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Plainville town	Connecticut	1
CT	0900365370	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Rocky Hill town	Connecticut	1
CT	0900368940	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Simsbury town	Connecticut	1
CT	0900370550	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Southington town	Connecticut	1
CT	0900371390	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	South Windsor town	Connecticut	1
CT	0900374540	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Suffield town	Connecticut	1
CT	0900382590	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	West Hartford town	Connecticut	1
CT	0900384900	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Wethersfield town	Connecticut	1
CT	0900387000	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Windsor town	Connecticut	1
CT	0900387070	9	3	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Hartford County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Windsor Locks town	Connecticut	1
CT	0900502760	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	3280	Barkhamsted town	Connecticut	0
CT	0900504930	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	8880	Bethlehem town	Connecticut	0
CT	0900508210	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	1930	Bridgewater town	Connecticut	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
CT	0900510940	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Canaan town	Connecticut	0
CT	0900516050	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Colebrook town	Connecticut	0
CT	0900517240	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Cornwall town	Connecticut	0
CT	0900532290	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Goshen town	Connecticut	0
CT	0900537280	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	3280	Harwinton town	Connecticut	0
CT	0900540290	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Kent town	Connecticut	0
CT	0900543370	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Litchfield town	Connecticut	0
CT	0900549460	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Morris town	Connecticut	0
CT	0900551350	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	3280	New Hartford town	Connecticut	0
CT	0900552630	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	1930	New Milford town	Connecticut	0
CT	0900553470	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Norfolk town	Connecticut	0
CT	0900554030	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	North Canaan town	Connecticut	0
CT	0900560750	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	3280	Plymouth town	Connecticut	0
CT	0900565930	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	1930	Roxbury town	Connecticut	0
CT	0900566420	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Salisbury town	Connecticut	0
CT	0900567960	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Sharon town	Connecticut	0
CT	0900575730	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	8880	Thomaston town	Connecticut	0
CT	0900576570	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Torrington town	Connecticut	0
CT	0900579510	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	9999	Warren town	Connecticut	0
CT	0900579720	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	1930	Washington town	Connecticut	0
CT	0900580490	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	8880	Watertown town	Connecticut	0
CT	0900586440	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	3280	Winchester town	Connecticut	0
CT	0900587910	9	5	NCNTY09005N09005	Litchfield County, CT	Litchfield County	102600	21600	24650	27750	30800	33300	35750	38200	40700	8880	Woodbury town	Connecticut	0
CT	0900714300	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	9999	Chester town	Connecticut	1
CT	0900715350	9	7	METRO25540MM5480	Southern Middlesex County, CT HUD Metro FMR Area	Middlesex County	112000	23550	26900	30250	33600	36300	39000	41700	44400	5480	Clinton town	Connecticut	1
CT	0900718080	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Cromwell town	Connecticut	1
CT	0900719130	9	7	METRO25540MM5480	Southern Middlesex County, CT HUD Metro FMR Area	Middlesex County	112000	23550	26900	30250	33600	36300	39000	41700	44400	9999	Deep River town	Connecticut	1
CT	0900720810	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Durham town	Connecticut	1
CT	0900722280	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	East Haddam town	Connecticut	1
CT	0900722490	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	East Hampton town	Connecticut	1
CT	0900726270	9	7	METRO25540MM5480	Southern Middlesex County, CT HUD Metro FMR Area	Middlesex County	112000	23550	26900	30250	33600	36300	39000	41700	44400	9999	Essex town	Connecticut	1
CT	0900735230	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Haddam town	Connecticut	1
CT	0900740710	9	7	METRO25540MM5480	Southern Middlesex County, CT HUD Metro FMR Area	Middlesex County	112000	23550	26900	30250	33600	36300	39000	41700	44400	5480	Killingworth town	Connecticut	1
CT	0900747080	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Middlefield town	Connecticut	1
CT	0900747360	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Middletown town	Connecticut	1
CT	0900757320	9	7	METRO25540MM5480	Southern Middlesex County, CT HUD Metro FMR Area	Middlesex County	112000	23550	26900	30250	33600	36300	39000	41700	44400	5520	Old Saybrook town	Connecticut	1
CT	0900761800	9	7	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Middlesex County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Portland town	Connecticut	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
CT	0900781680	9	7	METRO25540MM5480	Southern Middlesex County, CT HUD Metro FMR Area	Middlesex County	112000	23550	26900	30250	33600	36300	39000	41700	44400	9999	Westbrook town	Connecticut	1
CT	0900901220	9	9	METRO35300MM1160	Milford-Ansonia-Seymour, CT HUD Metro FMR Area	New Haven County	108200	22750	26000	29250	32450	35050	37650	40250	42850	1160	Ansonia town	Connecticut	1
CT	0900903250	9	9	METRO35300MM1160	Milford-Ansonia-Seymour, CT HUD Metro FMR Area	New Haven County	108200	22750	26000	29250	32450	35050	37650	40250	42850	1160	Beacon Falls town	Connecticut	1
CT	0900904580	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Bethany town	Connecticut	1
CT	0900907310	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Branford town	Connecticut	1
CT	0900914160	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Cheshire town	Connecticut	1
CT	0900919550	9	9	METRO35300MM1160	Milford-Ansonia-Seymour, CT HUD Metro FMR Area	New Haven County	108200	22750	26000	29250	32450	35050	37650	40250	42850	1160	Derby town	Connecticut	1
CT	0900922910	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	East Haven town	Connecticut	1
CT	0900934950	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Guilford town	Connecticut	1
CT	0900935650	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Hamden town	Connecticut	1
CT	0900944560	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Madison town	Connecticut	1
CT	0900946520	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Meriden town	Connecticut	1
CT	0900946940	9	9	METRO35300MM8880	Waterbury, CT HUD Metro FMR Area	New Haven County	80300	21600	24650	27750	30800	33300	35750	38200	40700	8880	Middlebury town	Connecticut	1
CT	0900947535	9	9	METRO35300MM1160	Milford-Ansonia-Seymour, CT HUD Metro FMR Area	New Haven County	108200	22750	26000	29250	32450	35050	37650	40250	42850	1160	Milford town	Connecticut	1
CT	0900949950	9	9	METRO35300MM8880	Waterbury, CT HUD Metro FMR Area	New Haven County	80300	21600	24650	27750	30800	33300	35750	38200	40700	8880	Naugatuck town	Connecticut	1
CT	0900952070	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	New Haven town	Connecticut	1
CT	0900953890	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	North Branford town	Connecticut	1
CT	0900954870	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	North Haven town	Connecticut	1
CT	0900957600	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Orange town	Connecticut	1
CT	0900958300	9	9	METRO35300MM1160	Milford-Ansonia-Seymour, CT HUD Metro FMR Area	New Haven County	108200	22750	26000	29250	32450	35050	37650	40250	42850	1160	Oxford town	Connecticut	1
CT	0900962290	9	9	METRO35300MM8880	Waterbury, CT HUD Metro FMR Area	New Haven County	80300	21600	24650	27750	30800	33300	35750	38200	40700	8880	Prospect town	Connecticut	1
CT	0900967610	9	9	METRO35300MM1160	Milford-Ansonia-Seymour, CT HUD Metro FMR Area	New Haven County	108200	22750	26000	29250	32450	35050	37650	40250	42850	1160	Seymour town	Connecticut	1
CT	0900969640	9	9	METRO35300MM8880	Waterbury, CT HUD Metro FMR Area	New Haven County	80300	21600	24650	27750	30800	33300	35750	38200	40700	8880	Southbury town	Connecticut	1
CT	0900978740	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Wallingford town	Connecticut	1
CT	0900980070	9	9	METRO35300MM8880	Waterbury, CT HUD Metro FMR Area	New Haven County	80300	21600	24650	27750	30800	33300	35750	38200	40700	8880	Waterbury town	Connecticut	1
CT	0900982870	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	West Haven town	Connecticut	1
CT	0900987560	9	9	METRO35300MM8880	Waterbury, CT HUD Metro FMR Area	New Haven County	80300	21600	24650	27750	30800	33300	35750	38200	40700	8880	Wolcott town	Connecticut	1
CT	0900987700	9	9	METRO35300MM5480	New Haven-Meriden, CT HUD Metro FMR Area	New Haven County	91200	21600	24650	27750	30800	33300	35750	38200	40700	5480	Woodbridge town	Connecticut	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
CT	0901106820	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Bozrah town	Connecticut	1
CT	0901115910	9	11	METRO35980MM3280	Colchester-Lebanon, CT HUD Metro FMR Area	New London County	115000	24150	27600	31050	34500	37300	40050	42800	45550	3280	Colchester town	Connecticut	1
CT	0901123400	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	East Lyme town	Connecticut	1
CT	0901129910	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Franklin town	Connecticut	1
CT	0901133900	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Griswold town	Connecticut	1
CT	0901134250	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Groton town	Connecticut	1
CT	0901142390	9	11	METRO35980MM3280	Colchester-Lebanon, CT HUD Metro FMR Area	New London County	115000	24150	27600	31050	34500	37300	40050	42800	45550	3280	Lebanon town	Connecticut	1
CT	0901142600	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Ledyard town	Connecticut	1
CT	0901143230	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Lisbon town	Connecticut	1
CT	0901144210	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	9999	Lyme town	Connecticut	1
CT	0901148900	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Montville town	Connecticut	1
CT	0901152350	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	New London town	Connecticut	1
CT	0901155500	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	North Stonington town	Connecticut	1
CT	0901156270	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Norwich town	Connecticut	1
CT	0901157040	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Old Lyme town	Connecticut	1
CT	0901162150	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Preston town	Connecticut	1
CT	0901166210	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Salem town	Connecticut	1
CT	0901171670	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Sprague town	Connecticut	1
CT	0901173770	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Stonington town	Connecticut	1
CT	0901178600	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	9999	Voluntown town	Connecticut	1
CT	0901180280	9	11	METRO35980M35980	Norwich-New London, CT HUD Metro FMR Area	New London County	91800	21600	24650	27750	30800	33300	35750	38200	40700	5520	Waterford town	Connecticut	1
CT	0901301080	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Andover town	Connecticut	1
CT	0901306260	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Bolton town	Connecticut	1
CT	0901316400	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Columbia town	Connecticut	1
CT	0901317800	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Coventry town	Connecticut	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
CT	0901325360	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Ellington town	Connecticut	1
CT	0901337910	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Hebron town	Connecticut	1
CT	0901344910	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Mansfield town	Connecticut	1
CT	0901369220	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Somers town	Connecticut	1
CT	0901372090	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Stafford town	Connecticut	1
CT	0901376290	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Tolland town	Connecticut	1
CT	0901377830	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	9999	Union town	Connecticut	1
CT	0901378250	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Vernon town	Connecticut	1
CT	0901385950	9	13	METRO25540M25540	Hartford-West Hartford-East Hartford, CT HUD Metro FMR Area	Tolland County	97400	21600	24650	27750	30800	33300	35750	38200	40700	3280	Willington town	Connecticut	1
CT	0901501430	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	3280	Ashford town	Connecticut	1
CT	0901509190	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Brooklyn town	Connecticut	1
CT	0901512130	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	5520	Canterbury town	Connecticut	1
CT	0901513810	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	3280	Chaplin town	Connecticut	1
CT	0901521860	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Eastford town	Connecticut	1
CT	0901536000	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Hampton town	Connecticut	1
CT	0901540500	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Killingly town	Connecticut	1
CT	0901559980	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	5520	Plainfield town	Connecticut	1
CT	0901561030	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Pomfret town	Connecticut	1
CT	0901562710	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Putnam town	Connecticut	1
CT	0901567400	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Scotland town	Connecticut	1
CT	0901573420	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Sterling town	Connecticut	1
CT	0901575870	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9240	Thompson town	Connecticut	1
CT	0901586790	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	3280	Windham town	Connecticut	1
CT	0901588190	9	15	METRO49340N09015	Windham County, CT HUD Metro FMR Area	Windham County	86900	21600	24650	27750	30800	33300	35750	38200	40700	9999	Woodstock town	Connecticut	1
DE	1000199999	10	1	METRO20100M20100	Dover, DE MSA	Kent County	68400	14350	16400	18450	20500	22150	23800	25450	27100	2190	Kent County	Delaware	1
DE	1000399999	10	3	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	New Castle County	96600	20300	23200	26100	29000	31350	33650	36000	38300	9160	New Castle County	Delaware	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
DE	1000599999	10	5	METRO41540N10005	Sussex County, DE HUD Metro FMR Area	Sussex County	75900	15950	18200	20500	22750	24600	26400	28250	30050	9999	Sussex County	Delaware	1
DC	1100199999	11	1	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	District of Columbia	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	District of Columbia	District of Columbia	1
FL	1200199999	12	1	METRO23540M23540	Gainesville, FL MSA	Alachua County	69800	14700	16800	18900	20950	22650	24350	26000	27700	2900	Alachua County	Florida	1
FL	1200399999	12	3	METRO27260N12003	Baker County, FL HUD Metro FMR Area	Baker County	71600	14950	17100	19250	21350	23100	24800	26500	28200	9999	Baker County	Florida	1
FL	1200599999	12	5	METRO37460M37460	Panama City-Lynn Haven-Panama City Beach, FL HUD Metro FMR Area	Bay County	72000	14600	16650	18750	20800	22500	24150	25800	27500	6015	Bay County	Florida	1
FL	1200799999	12	7	NCNTY12007N12007	Bradford County, FL	Bradford County	59500	12500	14300	16100	17850	19300	20750	22150	23600	9999	Bradford County	Florida	0
FL	1200999999	12	9	METRO37340M37340	Palm Bay-Melbourne-Titusville, FL MSA	Brevard County	69200	14550	16600	18700	20750	22450	24100	25750	27400	4900	Brevard County	Florida	1
FL	1201199999	12	11	METRO33100MM2680	Fort Lauderdale, FL HUD Metro FMR Area	Broward County	74800	18750	21400	24100	26750	28900	31050	33200	35350	2680	Broward County	Florida	1
FL	1201399999	12	13	NCNTY12013N12013	Calhoun County, FL	Calhoun County	47900	11100	12700	14300	15850	17150	18400	19700	20950	9999	Calhoun County	Florida	0
FL	1201599999	12	15	METRO39460M39460	Punta Gorda, FL MSA	Charlotte County	64100	13000	14850	16700	18550	20050	21550	23050	24500	6580	Charlotte County	Florida	1
FL	1201799999	12	17	METRO26140M26140	Homosassa Springs, FL MSA	Citrus County	55900	11750	13400	15100	16750	18100	19450	20800	22150	9999	Citrus County	Florida	1
FL	1201999999	12	19	METRO27260M27260	Jacksonville, FL HUD Metro FMR Area	Clay County	75000	15750	18000	20250	22500	24300	26100	27900	29700	3600	Clay County	Florida	1
FL	1202199999	12	21	METRO34940M34940	Naples-Immokalee-Marco Island, FL MSA	Collier County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5345	Collier County	Florida	1
FL	1202399999	12	23	NCNTY12023N12023	Columbia County, FL	Columbia County	55200	11800	13450	15150	16800	18150	19500	20850	22200	9999	Columbia County	Florida	0
FL	1202799999	12	27	NCNTY12027N12027	DeSoto County, FL	DeSoto County	42700	11100	12700	14300	15850	17150	18400	19700	20950	9999	DeSoto County	Florida	0
FL	1202999999	12	29	NCNTY12029N12029	Dixie County, FL	Dixie County	44600	11100	12700	14300	15850	17150	18400	19700	20950	9999	Dixie County	Florida	0
FL	1203199999	12	31	METRO27260M27260	Jacksonville, FL HUD Metro FMR Area	Duval County	75000	15750	18000	20250	22500	24300	26100	27900	29700	3600	Duval County	Florida	1
FL	1203399999	12	33	METRO37860M37860	Pensacola-Ferry Pass-Brent, FL MSA	Escambia County	65900	13850	15800	17800	19750	21350	22950	24500	26100	6080	Escambia County	Florida	1
FL	1203599999	12	35	METRO19660M37380	Palm Coast, FL HUD Metro FMR Area	Flagler County	65600	13800	15800	17750	19700	21300	22900	24450	26050	2020	Flagler County	Florida	1
FL	1203799999	12	37	NCNTY12037N12037	Franklin County, FL	Franklin County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Franklin County	Florida	0
FL	1203999999	12	39	METRO45220M45220	Tallahassee, FL HUD Metro FMR Area	Gadsden County	72700	15300	17450	19650	21800	23550	25300	27050	28800	8240	Gadsden County	Florida	1
FL	1204199999	12	41	METRO23540M23540	Gainesville, FL MSA	Gilchrist County	69800	14700	16800	18900	20950	22650	24350	26000	27700	9999	Gilchrist County	Florida	1
FL	1204399999	12	43	NCNTY12043N12043	Glades County, FL	Glades County	45900	11100	12700	14300	15850	17150	18400	19700	20950	9999	Glades County	Florida	0
FL	1204599999	12	45	METRO37460N12045	Gulf County, FL HUD Metro FMR Area	Gulf County	59300	12350	14100	15850	17600	19050	20450	21850	23250	9999	Gulf County	Florida	1
FL	1204799999	12	47	NCNTY12047N12047	Hamilton County, FL	Hamilton County	44600	11100	12700	14300	15850	17150	18400	19700	20950	9999	Hamilton County	Florida	0
FL	1204999999	12	49	NCNTY12049N12049	Hardee County, FL	Hardee County	49000	11100	12700	14300	15850	17150	18400	19700	20950	9999	Hardee County	Florida	0
FL	1205199999	12	51	NCNTY12051N12051	Hendry County, FL	Hendry County	47400	11100	12700	14300	15850	17150	18400	19700	20950	9999	Hendry County	Florida	0
FL	1205399999	12	53	METRO45300M45300	Tampa-St. Petersburg-Clearwater, FL MSA	Hernando County	69200	14800	16900	19000	21100	22800	24500	26200	27900	8280	Hernando County	Florida	1
FL	1205599999	12	55	METRO42700M42700	Sebring, FL MSA	Highlands County	49600	11100	12700	14300	15850	17150	18400	19700	20950	9999	Highlands County	Florida	1
FL	1205799999	12	57	METRO45300M45300	Tampa-St. Petersburg-Clearwater, FL MSA	Hillsborough County	69200	14800	16900	19000	21100	22800	24500	26200	27900	8280	Hillsborough County	Florida	1
FL	1205999999	12	59	NCNTY12059N12059	Holmes County, FL	Holmes County	51600	11100	12700	14300	15850	17150	18400	19700	20950	9999	Holmes County	Florida	0
FL	1206199999	12	61	METRO42680M42680	Sebastian-Vero Beach, FL MSA	Indian River County	69600	14650	16750	18850	20900	22600	24250	25950	27600	9999	Indian River County	Florida	1
FL	1206399999	12	63	NCNTY12063N12063	Jackson County, FL	Jackson County	51000	11100	12700	14300	15850	17150	18400	19700	20950	9999	Jackson County	Florida	0
FL	1206599999	12	65	METRO45220M45220	Tallahassee, FL HUD Metro FMR Area	Jefferson County	72700	15300	17450	19650	21800	23550	25300	27050	28800	9999	Jefferson County	Florida	1
FL	1206799999	12	67	NCNTY12067N12067	Lafayette County, FL	Lafayette County	60100	11750	13400	15100	16750	18100	19450	20800	22150	9999	Lafayette County	Florida	0
FL	1206999999	12	69	METRO36740M36740	Orlando-Kissimmee-Sanford, FL MSA	Lake County	68100	15300	17450	19650	21800	23550	25300	27050	28800	5960	Lake County	Florida	1
FL	1207199999	12	71	METRO15980M15980	Cape Coral-Fort Myers, FL MSA	Lee County	68700	14500	16550	18600	20650	22350	24000	25650	27300	2700	Lee County	Florida	1
FL	1207399999	12	73	METRO45220M45220	Tallahassee, FL HUD Metro FMR Area	Leon County	72700	15300	17450	19650	21800	23550	25300	27050	28800	8240	Leon County	Florida	1
FL	1207599999	12	75	NCNTY12075N12075	Levy County, FL	Levy County	47500	11100	12700	14300	15850	17150	18400	19700	20950	9999	Levy County	Florida	0
FL	1207799999	12	77	NCNTY12077N12077	Liberty County, FL	Liberty County	44500	11100	12700	14300	15850	17150	18400	19700	20950	9999	Liberty County	Florida	0
FL	1207999999	12	79	NCNTY12079N12079	Madison County, FL	Madison County	44000	11100	12700	14300	15850	17150	18400	19700	20950	9999	Madison County	Florida	0
FL	1208199999	12	81	METRO35840M35840	North Port-Sarasota-Bradenton, FL MSA	Manatee County	76700	16100	18400	20700	22950	24800	26650	28500	30300	7510	Manatee County	Florida	1
FL	1208399999	12	83	METRO36100M36100	Ocala, FL MSA	Marion County	55000	11550	13200	14850	16500	17850	19150	20500	21800	5790	Marion County	Florida	1
FL	1208599999	12	85	METRO38940M38940	Port St. Lucie, FL MSA	Martin County	67500	14600	16700	18800	20850	22550	24200	25900	27550	2710	Martin County	Florida	1
FL	1208699999	12	86	METRO33100MM5000	Miami-Miami Beach-Kendall, FL HUD Metro FMR Area	Miami-Dade County	59100	19200	21950	24700	27400	29600	31800	34000	36200	5000	Miami-Dade County	Florida	1
FL	1208799999	12	87	NCNTY12087N12087	Monroe County, FL	Monroe County	81400	21150	24200	27200	30200	32650	35050	37450	39900	9999	Monroe County	Florida	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
FL	1208999999	12	89	METRO27260M27260	Jacksonville, FL HUD Metro FMR Area	Nassau County	75000	15750	18000	20250	22500	24300	26100	27900	29700	3600	Nassau County	Florida	1
FL	1209199999	12	91	METRO18880M18880	Crestview-Fort Walton Beach-Destin, FL HUD Metro FMR Area	Okaloosa County	81600	16350	18700	21050	23350	25250	27100	29000	30850	2750	Okaloosa County	Florida	1
FL	1209399999	12	93	NCNTY12093N12093	Okeechobee County, FL	Okeechobee County	48500	11100	12700	14300	15850	17150	18400	19700	20950	9999	Okeechobee County	Florida	0
FL	1209599999	12	95	METRO36740M36740	Orlando-Kissimmee-Sanford, FL MSA	Orange County	68100	15300	17450	19650	21800	23550	25300	27050	28800	5960	Orange County	Florida	1
FL	1209799999	12	97	METRO36740M36740	Orlando-Kissimmee-Sanford, FL MSA	Osceola County	68100	15300	17450	19650	21800	23550	25300	27050	28800	5960	Osceola County	Florida	1
FL	1209999999	12	99	METRO33100MM8960	West Palm Beach-Boca Raton, FL HUD Metro FMR Area	Palm Beach County	79100	18450	21100	23750	26350	28500	30600	32700	34800	8960	Palm Beach County	Florida	1
FL	1210199999	12	101	METRO45300M45300	Tampa-St. Petersburg-Clearwater, FL MSA	Pasco County	69200	14800	16900	19000	21100	22800	24500	26200	27900	8280	Pasco County	Florida	1
FL	1210399999	12	103	METRO45300M45300	Tampa-St. Petersburg-Clearwater, FL MSA	Pinellas County	69200	14800	16900	19000	21100	22800	24500	26200	27900	8280	Pinellas County	Florida	1
FL	1210599999	12	105	METRO29460M29460	Lakeland-Winter Haven, FL MSA	Polk County	58800	12400	14150	15900	17650	19100	20500	21900	23300	3980	Polk County	Florida	1
FL	1210799999	12	107	NCNTY12107N12107	Putnam County, FL	Putnam County	41600	11100	12700	14300	15850	17150	18400	19700	20950	9999	Putnam County	Florida	0
FL	1210999999	12	109	METRO27260M27260	Jacksonville, FL HUD Metro FMR Area	St. Johns County	75000	15750	18000	20250	22500	24300	26100	27900	29700	3600	St. Johns County	Florida	1
FL	1211199999	12	111	METRO38940M38940	Port St. Lucie, FL MSA	St. Lucie County	67500	14600	16700	18800	20850	22550	24200	25900	27550	2710	St. Lucie County	Florida	1
FL	1211399999	12	113	METRO37860M37860	Pensacola-Ferry Pass-Brent, FL MSA	Santa Rosa County	65900	13850	15800	17800	19750	21350	22950	24500	26100	6080	Santa Rosa County	Florida	1
FL	1211599999	12	115	METRO35840M35840	North Port-Sarasota-Bradenton, FL MSA	Sarasota County	76700	16100	18400	20700	22950	24800	26650	28500	30300	7510	Sarasota County	Florida	1
FL	1211799999	12	117	METRO36740M36740	Orlando-Kissimmee-Sanford, FL MSA	Seminole County	68100	15300	17450	19650	21800	23550	25300	27050	28800	5960	Seminole County	Florida	1
FL	1211999999	12	119	METRO45540M45540	The Villages, FL MSA	Sumter County	67500	14250	16300	18350	20350	22000	23650	25250	26900	9999	Sumter County	Florida	1
FL	1212199999	12	121	NCNTY12121N12121	Suwannee County, FL	Suwannee County	51700	11100	12700	14300	15850	17150	18400	19700	20950	9999	Suwannee County	Florida	0
FL	1212399999	12	123	NCNTY12123N12123	Taylor County, FL	Taylor County	49100	11100	12700	14300	15850	17150	18400	19700	20950	9999	Taylor County	Florida	0
FL	1212599999	12	125	NCNTY12125N12125	Union County, FL	Union County	49700	11100	12700	14300	15850	17150	18400	19700	20950	9999	Union County	Florida	0
FL	1212799999	12	127	METRO19660M19660	Deltona-Daytona Beach-Ormond Beach, FL HUD Metro FMR Area	Volusia County	64900	13650	15600	17550	19450	21050	22600	24150	25700	2020	Volusia County	Florida	1
FL	1212999999	12	129	METRO45220N12129	Wakulla County, FL HUD Metro FMR Area	Wakulla County	70000	14700	16800	18900	20950	22650	24350	26000	27700	9999	Wakulla County	Florida	1
FL	1213199999	12	131	METRO18880N12131	Walton County, FL HUD Metro FMR Area	Walton County	66300	13950	15950	17950	19900	21500	23100	24700	26300	9999	Walton County	Florida	1
FL	1213399999	12	133	NCNTY12133N12133	Washington County, FL	Washington County	50700	11100	12700	14300	15850	17150	18400	19700	20950	9999	Washington County	Florida	0
GA	1300199999	13	1	NCNTY13001N13001	Appling County, GA	Appling County	49600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Appling County	Georgia	0
GA	1300399999	13	3	NCNTY13003N13003	Atkinson County, GA	Atkinson County	37500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Atkinson County	Georgia	0
GA	1300599999	13	5	NCNTY13005N13005	Bacon County, GA	Bacon County	49200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Bacon County	Georgia	0
GA	1300799999	13	7	METRO10500M10500	Albany, GA MSA	Baker County	52300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Baker County	Georgia	1
GA	1300999999	13	9	NCNTY13009N13009	Baldwin County, GA	Baldwin County	54900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Baldwin County	Georgia	0
GA	1301199999	13	11	NCNTY13011N13011	Banks County, GA	Banks County	51800	11500	13150	14800	16400	17750	19050	20350	21650	9999	Banks County	Georgia	0
GA	1301399999	13	13	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Barrow County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Barrow County	Georgia	1
GA	1301599999	13	15	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Bartow County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Bartow County	Georgia	1
GA	1301799999	13	17	NCNTY13017N13017	Ben Hill County, GA	Ben Hill County	39500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Ben Hill County	Georgia	0
GA	1301999999	13	19	NCNTY13019N13019	Berrien County, GA	Berrien County	47900	11500	13150	14800	16400	17750	19050	20350	21650	9999	Berrien County	Georgia	0
GA	1302199999	13	21	METRO31420M31420	Macon-Bibb County, GA HUD Metro FMR Area	Bibb County	59000	12250	14000	15750	17450	18850	20250	21650	23050	4680	Bibb County	Georgia	1
GA	1302399999	13	23	NCNTY13023N13023	Bleckley County, GA	Bleckley County	53400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Bleckley County	Georgia	0
GA	1302599999	13	25	METRO15260M15260	Brunswick, GA MSA	Brantley County	71200	13200	15050	16950	18800	20350	21850	23350	24850	9999	Brantley County	Georgia	1
GA	1302799999	13	27	METRO46660M46660	Valdosta, GA MSA	Brooks County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Brooks County	Georgia	1
GA	1302999999	13	29	METRO42340M42340	Savannah, GA MSA	Bryan County	72000	15150	17300	19450	21600	23350	25100	26800	28550	7520	Bryan County	Georgia	1
GA	1303199999	13	31	NCNTY13031N13031	Bulloch County, GA	Bulloch County	54900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Bulloch County	Georgia	0
GA	1303399999	13	33	METRO12260M12260	Augusta-Richmond County, GA-SC HUD Metro FMR Area	Burke County	65900	13850	15800	17800	19750	21350	22950	24500	26100	9999	Burke County	Georgia	1
GA	1303599999	13	35	METRO12060N13035	Butts County, GA HUD Metro FMR Area	Butts County	51600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Butts County	Georgia	1
GA	1303799999	13	37	NCNTY13037N13037	Calhoun County, GA	Calhoun County	39600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Calhoun County	Georgia	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
GA	1303999999	13	39	NCNTY13039N13039	Camden County, GA	Camden County	63000	13250	15150	17050	18900	20450	21950	23450	24950	9999	Camden County	Georgia	0
GA	1304399999	13	43	NCNTY13043N13043	Candler County, GA	Candler County	39300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Candler County	Georgia	0
GA	1304599999	13	45	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Carroll County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Carroll County	Georgia	1
GA	1304799999	13	47	METRO16860M16860	Chattanooga, TN-GA MSA	Catoosa County	72600	15300	17450	19650	21800	23550	25300	27050	28800	1560	Catoosa County	Georgia	1
GA	1304999999	13	49	NCNTY13049N13049	Charlton County, GA	Charlton County	57700	12150	13850	15600	17300	18700	20100	21500	22850	9999	Charlton County	Georgia	0
GA	1305199999	13	51	METRO42340M42340	Savannah, GA MSA	Chatham County	72000	15150	17300	19450	21600	23350	25100	26800	28550	7520	Chatham County	Georgia	1
GA	1305399999	13	53	METRO17980M17980	Columbus, GA-AL MSA	Chattahoochee County	62300	13100	15000	16850	18700	20200	21700	23200	24700	1800	Chattahoochee County	Georgia	1
GA	1305599999	13	55	NCNTY13055N13055	Chattooga County, GA	Chattooga County	46800	11500	13150	14800	16400	17750	19050	20350	21650	9999	Chattooga County	Georgia	0
GA	1305799999	13	57	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Cherokee County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Cherokee County	Georgia	1
GA	1305999999	13	59	METRO12020M12020	Athens-Clarke County, GA MSA	Clarke County	65600	13800	15800	17750	19700	21300	22900	24450	26050	500	Clarke County	Georgia	1
GA	1306199999	13	61	NCNTY13061N13061	Clay County, GA	Clay County	37400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Clay County	Georgia	0
GA	1306399999	13	63	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Clayton County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Clayton County	Georgia	1
GA	1306599999	13	65	NCNTY13065N13065	Clinch County, GA	Clinch County	46300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Clinch County	Georgia	0
GA	1306799999	13	67	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Cobb County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Cobb County	Georgia	1
GA	1306999999	13	69	NCNTY13069N13069	Coffee County, GA	Coffee County	48900	11500	13150	14800	16400	17750	19050	20350	21650	9999	Coffee County	Georgia	0
GA	1307199999	13	71	NCNTY13071N13071	Colquitt County, GA	Colquitt County	42500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Colquitt County	Georgia	0
GA	1307399999	13	73	METRO12260M12260	Augusta-Richmond County, GA-SC HUD Metro FMR Area	Columbia County	65900	13850	15800	17800	19750	21350	22950	24500	26100	600	Columbia County	Georgia	1
GA	1307599999	13	75	NCNTY13075N13075	Cook County, GA	Cook County	44400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Cook County	Georgia	0
GA	1307799999	13	77	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Coweta County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Coweta County	Georgia	1
GA	1307999999	13	79	METRO31420M31420	Macon-Bibb County, GA HUD Metro FMR Area	Crawford County	59000	12250	14000	15750	17450	18850	20250	21650	23050	9999	Crawford County	Georgia	1
GA	1308199999	13	81	NCNTY13081N13081	Crisp County, GA	Crisp County	41700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Crisp County	Georgia	0
GA	1308399999	13	83	METRO16860M16860	Chattanooga, TN-GA MSA	Dade County	72600	15300	17450	19650	21800	23550	25300	27050	28800	1560	Dade County	Georgia	1
GA	1308599999	13	85	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Dawson County	82700	17400	19850	22350	24800	26800	28800	30800	32750	9999	Dawson County	Georgia	1
GA	1308799999	13	87	NCNTY13087N13087	Decatur County, GA	Decatur County	50400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Decatur County	Georgia	0
GA	1308999999	13	89	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	DeKalb County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	DeKalb County	Georgia	1
GA	1309199999	13	91	NCNTY13091N13091	Dodge County, GA	Dodge County	49900	11500	13150	14800	16400	17750	19050	20350	21650	9999	Dodge County	Georgia	0
GA	1309399999	13	93	NCNTY13093N13093	Dooly County, GA	Dooly County	48800	11500	13150	14800	16400	17750	19050	20350	21650	9999	Dooly County	Georgia	0
GA	1309599999	13	95	METRO10500M10500	Albany, GA MSA	Dougherty County	52300	11500	13150	14800	16400	17750	19050	20350	21650	120	Dougherty County	Georgia	1
GA	1309799999	13	97	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Douglas County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Douglas County	Georgia	1
GA	1309999999	13	99	NCNTY13099N13099	Early County, GA	Early County	42700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Early County	Georgia	0
GA	1310199999	13	101	METRO46660M46660	Valdosta, GA MSA	Echols County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Echols County	Georgia	1
GA	1310399999	13	103	METRO42340M42340	Savannah, GA MSA	Effingham County	72000	15150	17300	19450	21600	23350	25100	26800	28550	7520	Effingham County	Georgia	1
GA	1310599999	13	105	NCNTY13105N13105	Elbert County, GA	Elbert County	47500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Elbert County	Georgia	0
GA	1310799999	13	107	NCNTY13107N13107	Emanuel County, GA	Emanuel County	43700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Emanuel County	Georgia	0
GA	1310999999	13	109	NCNTY13109N13109	Evans County, GA	Evans County	52200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Evans County	Georgia	0
GA	1311199999	13	111	NCNTY13111N13111	Fannin County, GA	Fannin County	59800	12150	13900	15650	17350	18750	20150	21550	22950	9999	Fannin County	Georgia	0
GA	1311399999	13	113	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Fayette County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Fayette County	Georgia	1
GA	1311599999	13	115	METRO40660M40660	Rome, GA MSA	Floyd County	58700	12350	14100	15850	17600	19050	20450	21850	23250	9999	Floyd County	Georgia	1

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GA	1311799999	13	117	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Forsyth County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Forsyth County	Georgia	1
GA	1311999999	13	119	NCNTY13119N13119	Franklin County, GA	Franklin County	52400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Franklin County	Georgia	0
GA	1312199999	13	121	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Fulton County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Fulton County	Georgia	1
GA	1312399999	13	123	NCNTY13123N13123	Gilmer County, GA	Gilmer County	58400	12250	14000	15750	17500	18900	20300	21700	23100	9999	Gilmer County	Georgia	0
GA	1312599999	13	125	NCNTY13125N13125	Glascock County, GA	Glascock County	64000	12550	14350	16150	17900	19350	20800	22200	23650	9999	Glascock County	Georgia	0
GA	1312799999	13	127	METRO15260M15260	Brunswick, GA MSA	Glynn County	71200	13200	15050	16950	18800	20350	21850	23350	24850	9999	Glynn County	Georgia	1
GA	1312999999	13	129	NCNTY13129N13129	Gordon County, GA	Gordon County	50200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Gordon County	Georgia	0
GA	1313199999	13	131	NCNTY13131N13131	Grady County, GA	Grady County	48400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Grady County	Georgia	0
GA	1313399999	13	133	NCNTY13133N13133	Greene County, GA	Greene County	63500	13150	15000	16900	18750	20250	21750	23250	24750	9999	Greene County	Georgia	0
GA	1313599999	13	135	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Gwinnett County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Gwinnett County	Georgia	1
GA	1313799999	13	137	NCNTY13137N13137	Habersham County, GA	Habersham County	58000	12200	13950	15700	17400	18800	20200	21600	23000	9999	Habersham County	Georgia	0
GA	1313999999	13	139	METRO23580M23580	Gainesville, GA MSA	Hall County	75500	15200	17350	19500	21650	23400	25150	26850	28600	9999	Hall County	Georgia	1
GA	1314199999	13	141	NCNTY13141N13141	Hancock County, GA	Hancock County	35200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Hancock County	Georgia	0
GA	1314399999	13	143	METRO12060N13143	Haralson County, GA HUD Metro FMR Area	Haralson County	57300	12050	13800	15500	17200	18600	20000	21350	22750	9999	Haralson County	Georgia	1
GA	1314599999	13	145	METRO17980M17980	Columbus, GA-AL MSA	Harris County	62300	13100	15000	16850	18700	20200	21700	23200	24700	1800	Harris County	Georgia	1
GA	1314799999	13	147	NCNTY13147N13147	Hart County, GA	Hart County	55300	11650	13300	14950	16600	17950	19300	20600	21950	9999	Hart County	Georgia	0
GA	1314999999	13	149	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Heard County	82700	17400	19850	22350	24800	26800	28800	30800	32750	9999	Heard County	Georgia	1
GA	1315199999	13	151	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Henry County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Henry County	Georgia	1
GA	1315399999	13	153	METRO47580M47580	Warner Robins, GA HUD Metro FMR Area	Houston County	69600	14750	16850	18950	21050	22750	24450	26150	27800	4680	Houston County	Georgia	1
GA	1315599999	13	155	NCNTY13155N13155	Irwin County, GA	Irwin County	51800	11500	13150	14800	16400	17750	19050	20350	21650	9999	Irwin County	Georgia	0
GA	1315799999	13	157	NCNTY13157N13157	Jackson County, GA	Jackson County	81000	15200	17350	19500	21650	23400	25150	26850	28600	9999	Jackson County	Georgia	0
GA	1315999999	13	159	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Jasper County	82700	17400	19850	22350	24800	26800	28800	30800	32750	9999	Jasper County	Georgia	1
GA	1316199999	13	161	NCNTY13161N13161	Jeff Davis County, GA	Jeff Davis County	47300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Jeff Davis County	Georgia	0
GA	1316399999	13	163	NCNTY13163N13163	Jefferson County, GA	Jefferson County	43900	11500	13150	14800	16400	17750	19050	20350	21650	9999	Jefferson County	Georgia	0
GA	1316599999	13	165	NCNTY13165N13165	Jenkins County, GA	Jenkins County	41500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Jenkins County	Georgia	0
GA	1316799999	13	167	NCNTY13167N13167	Johnson County, GA	Johnson County	51100	11500	13150	14800	16400	17750	19050	20350	21650	9999	Johnson County	Georgia	0
GA	1316999999	13	169	METRO31420M31420	Macon-Bibb County, GA HUD Metro FMR Area	Jones County	59000	12250	14000	15750	17450	18850	20250	21650	23050	4680	Jones County	Georgia	1
GA	1317199999	13	171	METRO12060N13171	Lamar County, GA HUD Metro FMR Area	Lamar County	57300	12050	13800	15500	17200	18600	20000	21350	22750	9999	Lamar County	Georgia	1
GA	1317399999	13	173	METRO46660M46660	Valdosta, GA MSA	Lanier County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Lanier County	Georgia	1
GA	1317599999	13	175	NCNTY13175N13175	Laurens County, GA	Laurens County	45700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Laurens County	Georgia	0
GA	1317799999	13	177	METRO10500M10500	Albany, GA MSA	Lee County	52300	11500	13150	14800	16400	17750	19050	20350	21650	120	Lee County	Georgia	1
GA	1317999999	13	179	METRO25980M25980	Hinesville, GA HUD Metro FMR Area	Liberty County	50200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Liberty County	Georgia	1
GA	1318199999	13	181	METRO12260N13181	Lincoln County, GA HUD Metro FMR Area	Lincoln County	52000	11500	13150	14800	16400	17750	19050	20350	21650	9999	Lincoln County	Georgia	1
GA	1318399999	13	183	METRO25980N13183	Long County, GA HUD Metro FMR Area	Long County	59100	12450	14200	16000	17750	19200	20600	22050	23450	9999	Long County	Georgia	1
GA	1318599999	13	185	METRO46660M46660	Valdosta, GA MSA	Lowndes County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Lowndes County	Georgia	1
GA	1318799999	13	187	NCNTY13187N13187	Lumpkin County, GA	Lumpkin County	59800	12600	14400	16200	17950	19400	20850	22300	23700	9999	Lumpkin County	Georgia	0
GA	1318999999	13	189	METRO12260M12260	Augusta-Richmond County, GA-SC HUD Metro FMR Area	McDuffie County	65900	13850	15800	17800	19750	21350	22950	24500	26100	600	McDuffie County	Georgia	1
GA	1319199999	13	191	METRO15260M15260	Brunswick, GA MSA	McIntosh County	71200	13200	15050	16950	18800	20350	21850	23350	24850	9999	McIntosh County	Georgia	1
GA	1319399999	13	193	NCNTY13193N13193	Macon County, GA	Macon County	41700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Macon County	Georgia	0
GA	1319599999	13	195	METRO12020M12020	Athens-Clarke County, GA MSA	Madison County	65600	13800	15800	17750	19700	21300	22900	24450	26050	500	Madison County	Georgia	1
GA	1319799999	13	197	METRO17980M17980	Columbus, GA-AL MSA	Marion County	62300	13100	15000	16850	18700	20200	21700	23200	24700	9999	Marion County	Georgia	1

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GA	1319999999	13	199	METRO12060N13199	Meriwether County, GA HUD Metro FMR Area	Meriwether County	51700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Meriwether County	Georgia	1
GA	1320199999	13	201	NCNTY13201N13201	Miller County, GA	Miller County	49800	11500	13150	14800	16400	17750	19050	20350	21650	9999	Miller County	Georgia	0
GA	1320599999	13	205	NCNTY13205N13205	Mitchell County, GA	Mitchell County	43300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Mitchell County	Georgia	0
GA	1320799999	13	207	METRO31420N13207	Monroe County, GA HUD Metro FMR Area	Monroe County	70600	14500	16550	18600	20650	22350	24000	25650	27300	9999	Monroe County	Georgia	1
GA	1320999999	13	209	NCNTY13209N13209	Montgomery County, GA	Montgomery County	51100	11500	13150	14800	16400	17750	19050	20350	21650	9999	Montgomery County	Georgia	0
GA	1321199999	13	211	METRO12060N13211	Morgan County, GA HUD Metro FMR Area	Morgan County	68000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Morgan County	Georgia	1
GA	1321399999	13	213	METRO19140N13213	Murray County, GA HUD Metro FMR Area	Murray County	51400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Murray County	Georgia	1
GA	1321599999	13	215	METRO17980M17980	Columbus, GA-AL MSA	Muscogee County	62300	13100	15000	16850	18700	20200	21700	23200	24700	1800	Muscogee County	Georgia	1
GA	1321799999	13	217	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Newton County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Newton County	Georgia	1
GA	1321999999	13	219	METRO12020M12020	Athens-Clarke County, GA MSA	Oconee County	65600	13800	15800	17750	19700	21300	22900	24450	26050	500	Oconee County	Georgia	1
GA	1322199999	13	221	METRO12020M12020	Athens-Clarke County, GA MSA	Oglethorpe County	65600	13800	15800	17750	19700	21300	22900	24450	26050	9999	Oglethorpe County	Georgia	1
GA	1322399999	13	223	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Paulding County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Paulding County	Georgia	1
GA	1322599999	13	225	METRO47580N13225	Peach County, GA HUD Metro FMR Area	Peach County	59500	12500	14300	16100	17850	19300	20750	22150	23600	4680	Peach County	Georgia	1
GA	1322799999	13	227	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Pickens County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Pickens County	Georgia	1
GA	1322999999	13	229	NCNTY13229N13229	Pierce County, GA	Pierce County	53500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Pierce County	Georgia	0
GA	1323199999	13	231	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Pike County	82700	17400	19850	22350	24800	26800	28800	30800	32750	9999	Pike County	Georgia	1
GA	1323399999	13	233	NCNTY13233N13233	Polk County, GA	Polk County	53000	11500	13150	14800	16400	17750	19050	20350	21650	9999	Polk County	Georgia	0
GA	1323599999	13	235	METRO47580N13235	Pulaski County, GA HUD Metro FMR Area	Pulaski County	52500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Pulaski County	Georgia	1
GA	1323799999	13	237	NCNTY13237N13237	Putnam County, GA	Putnam County	60900	12800	14600	16450	18250	19750	21200	22650	24100	9999	Putnam County	Georgia	0
GA	1323999999	13	239	NCNTY13239N13239	Quitman County, GA	Quitman County	39700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Quitman County	Georgia	0
GA	1324199999	13	241	NCNTY13241N13241	Rabun County, GA	Rabun County	54400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Rabun County	Georgia	0
GA	1324399999	13	243	NCNTY13243N13243	Randolph County, GA	Randolph County	37900	11500	13150	14800	16400	17750	19050	20350	21650	9999	Randolph County	Georgia	0
GA	1324599999	13	245	METRO12260M12260	Augusta-Richmond County, GA-SC HUD Metro FMR Area	Richmond County	65900	13850	15800	17800	19750	21350	22950	24500	26100	600	Richmond County	Georgia	1
GA	1324799999	13	247	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Rockdale County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Rockdale County	Georgia	1
GA	1324999999	13	249	NCNTY13249N13249	Schley County, GA	Schley County	48200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Schley County	Georgia	0
GA	1325199999	13	251	NCNTY13251N13251	Screven County, GA	Screven County	48100	11500	13150	14800	16400	17750	19050	20350	21650	9999	Screven County	Georgia	0
GA	1325399999	13	253	NCNTY13253N13253	Seminole County, GA	Seminole County	45400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Seminole County	Georgia	0
GA	1325599999	13	255	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Spalding County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Spalding County	Georgia	1
GA	1325799999	13	257	NCNTY13257N13257	Stephens County, GA	Stephens County	57900	12150	13900	15650	17350	18750	20150	21550	22950	9999	Stephens County	Georgia	0
GA	1325999999	13	259	NCNTY13259N13259	Stewart County, GA	Stewart County	30100	11500	13150	14800	16400	17750	19050	20350	21650	9999	Stewart County	Georgia	0
GA	1326199999	13	261	NCNTY13261N13261	Sumter County, GA	Sumter County	44200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Sumter County	Georgia	0
GA	1326399999	13	263	NCNTY13263N13263	Talbot County, GA	Talbot County	49000	11500	13150	14800	16400	17750	19050	20350	21650	9999	Talbot County	Georgia	0
GA	1326599999	13	265	NCNTY13265N13265	Taliaferro County, GA	Taliaferro County	44000	11500	13150	14800	16400	17750	19050	20350	21650	9999	Taliaferro County	Georgia	0
GA	1326799999	13	267	NCNTY13267N13267	Tattnall County, GA	Tattnall County	50100	11500	13150	14800	16400	17750	19050	20350	21650	9999	Tattnall County	Georgia	0
GA	1326999999	13	269	NCNTY13269N13269	Taylor County, GA	Taylor County	37900	11500	13150	14800	16400	17750	19050	20350	21650	9999	Taylor County	Georgia	0
GA	1327199999	13	271	NCNTY13271N13271	Telfair County, GA	Telfair County	38400	11500	13150	14800	16400	17750	19050	20350	21650	9999	Telfair County	Georgia	0
GA	1327399999	13	273	METRO10500M10500	Albany, GA MSA	Terrell County	52300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Terrell County	Georgia	1
GA	1327599999	13	275	NCNTY13275N13275	Thomas County, GA	Thomas County	53900	11500	13150	14800	16400	17750	19050	20350	21650	9999	Thomas County	Georgia	0
GA	1327799999	13	277	NCNTY13277N13277	Tift County, GA	Tift County	50000	11500	13150	14800	16400	17750	19050	20350	21650	9999	Tift County	Georgia	0
GA	1327999999	13	279	NCNTY13279N13279	Toombs County, GA	Toombs County	50300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Toombs County	Georgia	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
GA	1328199999	13	281	NCNTY13281N13281	Towns County, GA	Towns County	54900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Towns County	Georgia	0
GA	1328399999	13	283	NCNTY13283N13283	Treutlen County, GA	Treutlen County	55400	11800	13450	15150	16800	18150	19500	20850	22200	9999	Treutlen County	Georgia	0
GA	1328599999	13	285	NCNTY13285N13285	Troup County, GA	Troup County	60600	12450	14200	16000	17750	19200	20600	22050	23450	9999	Troup County	Georgia	0
GA	1328799999	13	287	NCNTY13287N13287	Turner County, GA	Turner County	49600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Turner County	Georgia	0
GA	1328999999	13	289	METRO31420M31420	Macon-Bibb County, GA HUD Metro FMR Area	Twiggs County	59000	12250	14000	15750	17450	18850	20250	21650	23050	4680	Twiggs County	Georgia	1
GA	1329199999	13	291	NCNTY13291N13291	Union County, GA	Union County	59200	12450	14200	16000	17750	19200	20600	22050	23450	9999	Union County	Georgia	0
GA	1329399999	13	293	NCNTY13293N13293	Upson County, GA	Upson County	50600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Upson County	Georgia	0
GA	1329599999	13	295	METRO16860M16860	Chattanooga, TN-GA MSA	Walker County	72600	15300	17450	19650	21800	23550	25300	27050	28800	1560	Walker County	Georgia	1
GA	1329799999	13	297	METRO12060M12060	Atlanta-Sandy Springs-Roswell, GA HUD Metro FMR Area	Walton County	82700	17400	19850	22350	24800	26800	28800	30800	32750	520	Walton County	Georgia	1
GA	1329999999	13	299	NCNTY13299N13299	Ware County, GA	Ware County	47700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Ware County	Georgia	0
GA	1330199999	13	301	NCNTY13301N13301	Warren County, GA	Warren County	48800	11500	13150	14800	16400	17750	19050	20350	21650	9999	Warren County	Georgia	0
GA	1330399999	13	303	NCNTY13303N13303	Washington County, GA	Washington County	49200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Washington County	Georgia	0
GA	1330599999	13	305	NCNTY13305N13305	Wayne County, GA	Wayne County	54300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Wayne County	Georgia	0
GA	1330799999	13	307	NCNTY13307N13307	Webster County, GA	Webster County	53800	11500	13150	14800	16400	17750	19050	20350	21650	9999	Webster County	Georgia	0
GA	1330999999	13	309	NCNTY13309N13309	Wheeler County, GA	Wheeler County	40700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Wheeler County	Georgia	0
GA	1331199999	13	311	NCNTY13311N13311	White County, GA	White County	55300	11650	13300	14950	16600	17950	19300	20600	21950	9999	White County	Georgia	0
GA	1331399999	13	313	METRO19140M19140	Dalton, GA HUD Metro FMR Area	Whitfield County	53100	11500	13150	14800	16400	17750	19050	20350	21650	9999	Whitfield County	Georgia	1
GA	1331599999	13	315	NCNTY13315N13315	Wilcox County, GA	Wilcox County	49500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Wilcox County	Georgia	0
GA	1331799999	13	317	NCNTY13317N13317	Wilkes County, GA	Wilkes County	52200	11500	13150	14800	16400	17750	19050	20350	21650	9999	Wilkes County	Georgia	0
GA	1331999999	13	319	NCNTY13319N13319	Wilkinson County, GA	Wilkinson County	53500	11500	13150	14800	16400	17750	19050	20350	21650	9999	Wilkinson County	Georgia	0
GA	1332199999	13	321	METRO10500M10500	Albany, GA MSA	Worth County	52300	11500	13150	14800	16400	17750	19050	20350	21650	9999	Worth County	Georgia	1
HI	1500199999	15	1	NCNTY15001N15001	Hawaii County, HI	Hawaii County	75200	17500	20000	22500	25000	27000	29000	31000	33000	9999	Hawaii County	Hawaii	0
HI	1500399999	15	3	METRO46520M46520	Urban Honolulu, HI MSA	Honolulu County	101600	26450	30200	34000	37750	40800	43800	46850	49850	3320	Honolulu County	Hawaii	1
HI	1500599999	15	5	METRO27980M27980	Kahului-Wailuku-Lahaina, HI MSA	Kalawao County	97500	21550	24600	27700	30750	33250	35700	38150	40600	9999	Kalawao County	Hawaii	1
HI	1500799999	15	7	NCNTY15007N15007	Kauai County, HI	Kauai County	101800	20450	23350	26250	29150	31500	33850	36150	38500	9999	Kauai County	Hawaii	0
HI	1500999999	15	9	METRO27980M27980	Kahului-Wailuku-Lahaina, HI MSA	Maui County	97500	21550	24600	27700	30750	33250	35700	38150	40600	9999	Maui County	Hawaii	1
ID	1600199999	16	1	METRO14260M14260	Boise City, ID HUD Metro FMR Area	Ada County	74800	15750	18000	20250	22450	24250	26050	27850	29650	1080	Ada County	Idaho	1
ID	1600399999	16	3	NCNTY16003N16003	Adams County, ID	Adams County	59300	12800	14600	16450	18250	19750	21200	22650	24100	9999	Adams County	Idaho	0
ID	1600599999	16	5	METRO38540M38540	Pocatello, ID MSA	Bannock County	66000	13900	15850	17850	19800	21400	23000	24600	26150	6340	Bannock County	Idaho	1
ID	1600799999	16	7	NCNTY16007N16007	Bear Lake County, ID	Bear Lake County	65700	13800	15800	17750	19700	21300	22900	24450	26050	9999	Bear Lake County	Idaho	0
ID	1600999999	16	9	NCNTY16009N16009	Benewah County, ID	Benewah County	54900	12800	14600	16450	18250	19750	21200	22650	24100	9999	Benewah County	Idaho	0
ID	1601199999	16	11	NCNTY16011N16011	Bingham County, ID	Bingham County	64200	13500	15400	17350	19250	20800	22350	23900	25450	9999	Bingham County	Idaho	0
ID	1601399999	16	13	NCNTY16013N16013	Blaine County, ID	Blaine County	78400	16450	18800	21150	23500	25400	27300	29150	31050	9999	Blaine County	Idaho	0
ID	1601599999	16	15	METRO14260M14260	Boise City, ID HUD Metro FMR Area	Boise County	74800	15750	18000	20250	22450	24250	26050	27850	29650	9999	Boise County	Idaho	1
ID	1601799999	16	17	NCNTY16017N16017	Bonner County, ID	Bonner County	61500	12950	14800	16650	18450	19950	21450	22900	24400	9999	Bonner County	Idaho	0
ID	1601999999	16	19	METRO26820M26820	Idaho Falls, ID HUD Metro FMR Area	Bonneville County	70500	14850	16950	19050	21150	22850	24550	26250	27950	9999	Bonneville County	Idaho	1
ID	1602199999	16	21	NCNTY16021N16021	Boundary County, ID	Boundary County	63900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Boundary County	Idaho	0
ID	1602399999	16	23	METRO26820N16023	Butte County, ID HUD Metro FMR Area	Butte County	55200	12800	14600	16450	18250	19750	21200	22650	24100	9999	Butte County	Idaho	1
ID	1602599999	16	25	NCNTY16025N16025	Camas County, ID	Camas County	57200	12800	14600	16450	18250	19750	21200	22650	24100	9999	Camas County	Idaho	0
ID	1602799999	16	27	METRO14260M14260	Boise City, ID HUD Metro FMR Area	Canyon County	74800	15750	18000	20250	22450	24250	26050	27850	29650	1080	Canyon County	Idaho	1
ID	1602999999	16	29	NCNTY16029N16029	Caribou County, ID	Caribou County	70400	14800	16900	19000	21100	22800	24500	26200	27900	9999	Caribou County	Idaho	0
ID	1603199999	16	31	NCNTY16031N16031	Cassia County, ID	Cassia County	55800	12800	14600	16450	18250	19750	21200	22650	24100	9999	Cassia County	Idaho	0
ID	1603399999	16	33	NCNTY16033N16033	Clark County, ID	Clark County	60900	12800	14600	16450	18250	19750	21200	22650	24100	9999	Clark County	Idaho	0
ID	1603599999	16	35	NCNTY16035N16035	Clearwater County, ID	Clearwater County	55600	12800	14600	16450	18250	19750	21200	22650	24100	9999	Clearwater County	Idaho	0
ID	1603799999	16	37	NCNTY16037N16037	Custer County, ID	Custer County	53900	12800	14600	16450	18250	19750	21200	22650	24100	9999	Custer County	Idaho	0
ID	1603999999	16	39	NCNTY16039N16039	Elmore County, ID	Elmore County	57000	12800	14600	16450	18250	19750	21200	22650	24100	9999	Elmore County	Idaho	0
ID	1604199999	16	41	METRO30860M30860	Logan, UT-ID MSA	Franklin County	71000	15600	17800	20050	22250	24050	25850	27600	29400	9999	Franklin County	Idaho	1
ID	1604399999	16	43	NCNTY16043N16043	Fremont County, ID	Fremont County	63000	13250	15150	17050	18900	20450	21950	23450	24950	9999	Fremont County	Idaho	0
ID	1604599999	16	45	METRO14260N16045	Gem County, ID HUD Metro FMR Area	Gem County	53200	12800	14600	16450	18250	19750	21200	22650	24100	9999	Gem County	Idaho	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ID	1604799999	16	47	NCNTY16047N16047	Gooding County, ID	Gooding County	55900	12800	14600	16450	18250	19750	21200	22650	24100	9999	Gooding County	Idaho	0
ID	1604999999	16	49	NCNTY16049N16049	Idaho County, ID	Idaho County	53000	12800	14600	16450	18250	19750	21200	22650	24100	9999	Idaho County	Idaho	0
ID	1605199999	16	51	METRO26820M26820	Idaho Falls, ID HUD Metro FMR Area	Jefferson County	70500	14850	16950	19050	21150	22850	24550	26250	27950	9999	Jefferson County	Idaho	1
ID	1605399999	16	53	NCNTY16053N16053	Jerome County, ID	Jerome County	55300	12800	14600	16450	18250	19750	21200	22650	24100	9999	Jerome County	Idaho	0
ID	1605599999	16	55	METRO17660M17660	Coeur d'Alene, ID MSA	Kootenai County	70400	14650	16750	18850	20900	22600	24250	25950	27600	9999	Kootenai County	Idaho	1
ID	1605799999	16	57	NCNTY16057N16057	Latah County, ID	Latah County	70600	14850	17000	19100	21200	22900	24600	26300	28000	9999	Latah County	Idaho	0
ID	1605999999	16	59	NCNTY16059N16059	Lemhi County, ID	Lemhi County	53000	12800	14600	16450	18250	19750	21200	22650	24100	9999	Lemhi County	Idaho	0
ID	1606199999	16	61	NCNTY16061N16061	Lewis County, ID	Lewis County	54000	12800	14600	16450	18250	19750	21200	22650	24100	9999	Lewis County	Idaho	0
ID	1606399999	16	63	NCNTY16063N16063	Lincoln County, ID	Lincoln County	58500	12800	14600	16450	18250	19750	21200	22650	24100	9999	Lincoln County	Idaho	0
ID	1606599999	16	65	NCNTY16065N16065	Madison County, ID	Madison County	38800	12800	14600	16450	18250	19750	21200	22650	24100	9999	Madison County	Idaho	0
ID	1606799999	16	67	NCNTY16067N16067	Minidoka County, ID	Minidoka County	55100	12800	14600	16450	18250	19750	21200	22650	24100	9999	Minidoka County	Idaho	0
ID	1606999999	16	69	METRO30300M30300	Lewiston, ID-WA MSA	Nez Perce County	73900	14350	16400	18450	20450	22100	23750	25400	27000	9999	Nez Perce County	Idaho	1
ID	1607199999	16	71	NCNTY16071N16071	Oneida County, ID	Oneida County	64600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Oneida County	Idaho	0
ID	1607399999	16	73	METRO14260M14260	Boise City, ID HUD Metro FMR Area	Owyhee County	74800	15750	18000	20250	22450	24250	26050	27850	29650	9999	Owyhee County	Idaho	1
ID	1607599999	16	75	NCNTY16075N16075	Payette County, ID	Payette County	59300	12800	14600	16450	18250	19750	21200	22650	24100	9999	Payette County	Idaho	0
ID	1607799999	16	77	NCNTY16077N16077	Power County, ID	Power County	58500	12800	14600	16450	18250	19750	21200	22650	24100	9999	Power County	Idaho	0
ID	1607999999	16	79	NCNTY16079N16079	Shoshone County, ID	Shoshone County	53600	12800	14600	16450	18250	19750	21200	22650	24100	9999	Shoshone County	Idaho	0
ID	1608199999	16	81	NCNTY16081N16081	Teton County, ID	Teton County	72800	15300	17500	19700	21850	23600	25350	27100	28850	9999	Teton County	Idaho	0
ID	1608399999	16	83	NCNTY16083N16083	Twin Falls County, ID	Twin Falls County	60700	13050	14900	16750	18600	20100	21600	23100	24600	9999	Twin Falls County	Idaho	0
ID	1608599999	16	85	NCNTY16085N16085	Valley County, ID	Valley County	67400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Valley County	Idaho	0
ID	1608799999	16	87	NCNTY16087N16087	Washington County, ID	Washington County	50900	12800	14600	16450	18250	19750	21200	22650	24100	9999	Washington County	Idaho	0
IL	1700199999	17	1	NCNTY17001N17001	Adams County, IL	Adams County	67300	14250	16250	18300	20300	21950	23550	25200	26800	9999	Adams County	Illinois	0
IL	1700399999	17	3	METRO16020M16020	Cape Girardeau, MO-IL MSA	Alexander County	67000	14100	16100	18100	20100	21750	23350	24950	26550	9999	Alexander County	Illinois	1
IL	1700599999	17	5	METRO41180N17005	Bond County, IL HUD Metro FMR Area	Bond County	71900	15100	17250	19400	21550	23300	25000	26750	28450	9999	Bond County	Illinois	1
IL	1700799999	17	7	METRO40420M40420	Rockford, IL MSA	Boone County	69600	14650	16750	18850	20900	22600	24250	25950	27600	6880	Boone County	Illinois	1
IL	1700999999	17	9	NCNTY17009N17009	Brown County, IL	Brown County	77600	16350	18650	21000	23300	25200	27050	28900	30800	9999	Brown County	Illinois	0
IL	1701199999	17	11	NCNTY17011N17011	Bureau County, IL	Bureau County	71400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Bureau County	Illinois	0
IL	1701399999	17	13	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Calhoun County	82900	17400	19900	22400	24850	26850	28850	30850	32850	9999	Calhoun County	Illinois	1
IL	1701599999	17	15	NCNTY17015N17015	Carroll County, IL	Carroll County	67800	14250	16300	18350	20350	22000	23650	25250	26900	9999	Carroll County	Illinois	0
IL	1701799999	17	17	NCNTY17017N17017	Cass County, IL	Cass County	64100	14250	16250	18300	20300	21950	23550	25200	26800	9999	Cass County	Illinois	0
IL	1701999999	17	19	METRO16580M16580	Champaign-Urbana, IL MSA	Champaign County	83600	17600	20100	22600	25100	27150	29150	31150	33150	1400	Champaign County	Illinois	1
IL	1702199999	17	21	NCNTY17021N17021	Christian County, IL	Christian County	64300	14250	16250	18300	20300	21950	23550	25200	26800	9999	Christian County	Illinois	0
IL	1702399999	17	23	NCNTY17023N17023	Clark County, IL	Clark County	63700	14250	16250	18300	20300	21950	23550	25200	26800	9999	Clark County	Illinois	0
IL	1702599999	17	25	NCNTY17025N17025	Clay County, IL	Clay County	64500	14250	16250	18300	20300	21950	23550	25200	26800	9999	Clay County	Illinois	0
IL	1702799999	17	27	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Clinton County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Clinton County	Illinois	1
IL	1702999999	17	29	NCNTY17029N17029	Coles County, IL	Coles County	62800	14250	16250	18300	20300	21950	23550	25200	26800	9999	Coles County	Illinois	0
IL	1703199999	17	31	METRO16980M16980	Chicago-Joliet-Naperville, IL HUD Metro FMR Area	Cook County	91000	19150	21850	24600	27300	29500	31700	33900	36050	1600	Cook County	Illinois	1
IL	1703399999	17	33	NCNTY17033N17033	Crawford County, IL	Crawford County	66000	14250	16250	18300	20300	21950	23550	25200	26800	9999	Crawford County	Illinois	0
IL	1703599999	17	35	NCNTY17035N17035	Cumberland County, IL	Cumberland County	67400	14250	16250	18300	20300	21950	23550	25200	26800	9999	Cumberland County	Illinois	0
IL	1703799999	17	37	METRO16980MM2050	DeKalb County, IL HUD Metro FMR Area	DeKalb County	83700	17550	20050	22550	25050	27100	29100	31100	33100	2050	DeKalb County	Illinois	1
IL	1703999999	17	39	METRO14010N17039	De Witt County, IL HUD Metro FMR Area	De Witt County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9999	De Witt County	Illinois	1
IL	1704199999	17	41	NCNTY17041N17041	Douglas County, IL	Douglas County	68000	14300	16350	18400	20400	22050	23700	25300	26950	9999	Douglas County	Illinois	0
IL	1704399999	17	43	METRO16980M16980	Chicago-Joliet-Naperville, IL HUD Metro FMR Area	DuPage County	91000	19150	21850	24600	27300	29500	31700	33900	36050	1600	DuPage County	Illinois	1
IL	1704599999	17	45	NCNTY17045N17045	Edgar County, IL	Edgar County	63000	14250	16250	18300	20300	21950	23550	25200	26800	9999	Edgar County	Illinois	0
IL	1704799999	17	47	NCNTY17047N17047	Edwards County, IL	Edwards County	67700	14250	16250	18300	20300	21950	23550	25200	26800	9999	Edwards County	Illinois	0
IL	1704999999	17	49	NCNTY17049N17049	Effingham County, IL	Effingham County	75200	15800	18050	20300	22550	24400	26200	28000	29800	9999	Effingham County	Illinois	0
IL	1705199999	17	51	NCNTY17051N17051	Fayette County, IL	Fayette County	57000	14250	16250	18300	20300	21950	23550	25200	26800	9999	Fayette County	Illinois	0
IL	1705399999	17	53	METRO16580M16580	Champaign-Urbana, IL MSA	Ford County	83600	17600	20100	22600	25100	27150	29150	31150	33150	9999	Ford County	Illinois	1
IL	1705599999	17	55	NCNTY17055N17055	Franklin County, IL	Franklin County	54200	14250	16250	18300	20300	21950	23550	25200	26800	9999	Franklin County	Illinois	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
IL	1705799999	17	57	NCNTY17057N17057	Fulton County, IL	Fulton County	64200	14250	16250	18300	20300	21950	23550	25200	26800	9999	Fulton County	Illinois	0
IL	1705999999	17	59	NCNTY17059N17059	Gallatin County, IL	Gallatin County	55400	14250	16250	18300	20300	21950	23550	25200	26800	9999	Gallatin County	Illinois	0
IL	1706199999	17	61	NCNTY17061N17061	Greene County, IL	Greene County	57200	14250	16250	18300	20300	21950	23550	25200	26800	9999	Greene County	Illinois	0
IL	1706399999	17	63	METRO16980MM3170	Grundy County, IL HUD Metro FMR Area	Grundy County	88900	18700	21350	24000	26650	28800	30950	33050	35200	3170	Grundy County	Illinois	1
IL	1706599999	17	65	NCNTY17065N17065	Hamilton County, IL	Hamilton County	62800	14250	16250	18300	20300	21950	23550	25200	26800	9999	Hamilton County	Illinois	0
IL	1706799999	17	67	NCNTY17067N17067	Hancock County, IL	Hancock County	65200	14250	16250	18300	20300	21950	23550	25200	26800	9999	Hancock County	Illinois	0
IL	1706999999	17	69	NCNTY17069N17069	Hardin County, IL	Hardin County	59100	14250	16250	18300	20300	21950	23550	25200	26800	9999	Hardin County	Illinois	0
IL	1707199999	17	71	NCNTY17071N17071	Henderson County, IL	Henderson County	58500	14250	16250	18300	20300	21950	23550	25200	26800	9999	Henderson County	Illinois	0
IL	1707399999	17	73	METRO19340M19340	Davenport-Moline-Rock Island, IA-IL MSA	Henry County	75400	15850	18100	20350	22600	24450	26250	28050	29850	1960	Henry County	Illinois	1
IL	1707599999	17	75	NCNTY17075N17075	Iroquois County, IL	Iroquois County	64900	14250	16250	18300	20300	21950	23550	25200	26800	9999	Iroquois County	Illinois	0
IL	1707799999	17	77	METRO16060N17077	Jackson County, IL HUD Metro FMR Area	Jackson County	60300	14250	16250	18300	20300	21950	23550	25200	26800	9999	Jackson County	Illinois	1
IL	1707999999	17	79	NCNTY17079N17079	Jasper County, IL	Jasper County	71800	15100	17250	19400	21550	23300	25000	26750	28450	9999	Jasper County	Illinois	0
IL	1708199999	17	81	NCNTY17081N17081	Jefferson County, IL	Jefferson County	62500	14250	16250	18300	20300	21950	23550	25200	26800	9999	Jefferson County	Illinois	0
IL	1708399999	17	83	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Jersey County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Jersey County	Illinois	1
IL	1708599999	17	85	NCNTY17085N17085	Jo Daviess County, IL	Jo Daviess County	76200	16000	18300	20600	22850	24700	26550	28350	30200	9999	Jo Daviess County	Illinois	0
IL	1708799999	17	87	NCNTY17087N17087	Johnson County, IL	Johnson County	61300	14250	16250	18300	20300	21950	23550	25200	26800	9999	Johnson County	Illinois	0
IL	1708999999	17	89	METRO16980M16980	Chicago-Joliet-Naperville, IL HUD Metro FMR Area	Kane County	91000	19150	21850	24600	27300	29500	31700	33900	36050	1600	Kane County	Illinois	1
IL	1709199999	17	91	METRO28100M28100	Kankakee, IL MSA	Kankakee County	76500	15700	17950	20200	22400	24200	26000	27800	29600	3740	Kankakee County	Illinois	1
IL	1709399999	17	93	METRO16980MM3780	Kendall County, IL HUD Metro FMR Area	Kendall County	107300	22550	25800	29000	32200	34800	37400	39950	42550	3780	Kendall County	Illinois	1
IL	1709599999	17	95	NCNTY17095N17095	Knox County, IL	Knox County	61300	14250	16250	18300	20300	21950	23550	25200	26800	9999	Knox County	Illinois	0
IL	1709799999	17	97	METRO16980M16980	Chicago-Joliet-Naperville, IL HUD Metro FMR Area	Lake County	91000	19150	21850	24600	27300	29500	31700	33900	36050	1600	Lake County	Illinois	1
IL	1709999999	17	99	NCNTY17099N17099	La Salle County, IL	La Salle County	69300	15000	17150	19300	21400	23150	24850	26550	28250	9999	La Salle County	Illinois	0
IL	1710199999	17	101	NCNTY17101N17101	Lawrence County, IL	Lawrence County	59200	14250	16250	18300	20300	21950	23550	25200	26800	9999	Lawrence County	Illinois	0
IL	1710399999	17	103	NCNTY17103N17103	Lee County, IL	Lee County	76000	16000	18250	20550	22800	24650	26450	28300	30100	9999	Lee County	Illinois	0
IL	1710599999	17	105	NCNTY17105N17105	Livingston County, IL	Livingston County	74200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Livingston County	Illinois	0
IL	1710799999	17	107	NCNTY17107N17107	Logan County, IL	Logan County	75000	15600	17800	20050	22250	24050	25850	27600	29400	9999	Logan County	Illinois	0
IL	1710999999	17	109	NCNTY17109N17109	McDonough County, IL	McDonough County	71700	15050	17200	19350	21500	23250	24950	26700	28400	9999	McDonough County	Illinois	0
IL	1711199999	17	111	METRO16980M16980	Chicago-Joliet-Naperville, IL HUD Metro FMR Area	McHenry County	91000	19150	21850	24600	27300	29500	31700	33900	36050	1600	McHenry County	Illinois	1
IL	1711399999	17	113	METRO14010M14060	Bloomington, IL HUD Metro FMR Area	McLean County	98400	20050	22900	25750	28600	30900	33200	35500	37800	1040	McLean County	Illinois	1
IL	1711599999	17	115	METRO19500M19500	Decatur, IL MSA	Macon County	71300	15000	17150	19300	21400	23150	24850	26550	28250	2040	Macon County	Illinois	1
IL	1711799999	17	117	METRO41180N17117	Macoupin County, IL HUD Metro FMR Area	Macoupin County	68900	14500	16550	18600	20650	22350	24000	25650	27300	9999	Macoupin County	Illinois	1
IL	1711999999	17	119	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Madison County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Madison County	Illinois	1
IL	1712199999	17	121	NCNTY17121N17121	Marion County, IL	Marion County	60000	14250	16250	18300	20300	21950	23550	25200	26800	9999	Marion County	Illinois	0
IL	1712399999	17	123	METRO37900M37900	Peoria, IL MSA	Marshall County	79600	16750	19150	21550	23900	25850	27750	29650	31550	9999	Marshall County	Illinois	1
IL	1712599999	17	125	NCNTY17125N17125	Mason County, IL	Mason County	59900	14250	16250	18300	20300	21950	23550	25200	26800	9999	Mason County	Illinois	0
IL	1712799999	17	127	NCNTY17127N17127	Massac County, IL	Massac County	60100	14250	16250	18300	20300	21950	23550	25200	26800	9999	Massac County	Illinois	0
IL	1712999999	17	129	METRO44100M44100	Springfield, IL MSA	Menard County	85200	17300	19800	22250	24700	26700	28700	30650	32650	7880	Menard County	Illinois	1
IL	1713199999	17	131	METRO19340M19340	Davenport-Moline-Rock Island, IA-IL MSA	Mercer County	75400	15850	18100	20350	22600	24450	26250	28050	29850	9999	Mercer County	Illinois	1
IL	1713399999	17	133	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Monroe County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Monroe County	Illinois	1
IL	1713599999	17	135	NCNTY17135N17135	Montgomery County, IL	Montgomery County	63500	14250	16250	18300	20300	21950	23550	25200	26800	9999	Montgomery County	Illinois	0
IL	1713799999	17	137	NCNTY17137N17137	Morgan County, IL	Morgan County	65400	14250	16250	18300	20300	21950	23550	25200	26800	9999	Morgan County	Illinois	0
IL	1713999999	17	139	NCNTY17139N17139	Moultrie County, IL	Moultrie County	67000	14250	16250	18300	20300	21950	23550	25200	26800	9999	Moultrie County	Illinois	0
IL	1714199999	17	141	NCNTY17141N17141	Ogle County, IL	Ogle County	75100	15800	18050	20300	22550	24400	26200	28000	29800	6880	Ogle County	Illinois	0
IL	1714399999	17	143	METRO37900M37900	Peoria, IL MSA	Peoria County	79600	16750	19150	21550	23900	25850	27750	29650	31550	6120	Peoria County	Illinois	1
IL	1714599999	17	145	NCNTY17145N17145	Perry County, IL	Perry County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Perry County	Illinois	0
IL	1714799999	17	147	METRO16580M16580	Champaign-Urbana, IL MSA	Piatt County	83600	17600	20100	22600	25100	27150	29150	31150	33150	9999	Piatt County	Illinois	1

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IL	1714999999	17	149	NCNTY17149N17149	Pike County, IL	Pike County	56400	14250	16250	18300	20300	21950	23550	25200	26800	9999	Pike County	Illinois	0
IL	1715199999	17	151	NCNTY17151N17151	Pope County, IL	Pope County	60800	14250	16250	18300	20300	21950	23550	25200	26800	9999	Pope County	Illinois	0
IL	1715399999	17	153	NCNTY17153N17153	Pulaski County, IL	Pulaski County	54400	14250	16250	18300	20300	21950	23550	25200	26800	9999	Pulaski County	Illinois	0
IL	1715599999	17	155	NCNTY17155N17155	Putnam County, IL	Putnam County	84100	17700	20200	22750	25250	27300	29300	31350	33350	9999	Putnam County	Illinois	0
IL	1715799999	17	157	NCNTY17157N17157	Randolph County, IL	Randolph County	69100	14550	16600	18700	20750	22450	24100	25750	27400	9999	Randolph County	Illinois	0
IL	1715999999	17	159	NCNTY17159N17159	Richland County, IL	Richland County	62100	14250	16250	18300	20300	21950	23550	25200	26800	9999	Richland County	Illinois	0
IL	1716199999	17	161	METRO19340M19340	Davenport-Moline-Rock Island, IA-IL MSA	Rock Island County	75400	15850	18100	20350	22600	24450	26250	28050	29850	1960	Rock Island County	Illinois	1
IL	1716399999	17	163	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	St. Clair County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	St. Clair County	Illinois	1
IL	1716599999	17	165	NCNTY17165N17165	Saline County, IL	Saline County	55100	14250	16250	18300	20300	21950	23550	25200	26800	9999	Saline County	Illinois	0
IL	1716799999	17	167	METRO44100M44100	Springfield, IL MSA	Sangamon County	85200	17300	19800	22250	24700	26700	28700	30650	32650	7880	Sangamon County	Illinois	1
IL	1716999999	17	169	NCNTY17169N17169	Schuyler County, IL	Schuyler County	63500	14250	16250	18300	20300	21950	23550	25200	26800	9999	Schuyler County	Illinois	0
IL	1717199999	17	171	NCNTY17171N17171	Scott County, IL	Scott County	68700	14450	16500	18550	20600	22250	23900	25550	27200	9999	Scott County	Illinois	0
IL	1717399999	17	173	NCNTY17173N17173	Shelby County, IL	Shelby County	63300	14250	16250	18300	20300	21950	23550	25200	26800	9999	Shelby County	Illinois	0
IL	1717599999	17	175	METRO37900M37900	Peoria, IL MSA	Stark County	79600	16750	19150	21550	23900	25850	27750	29650	31550	9999	Stark County	Illinois	1
IL	1717799999	17	177	NCNTY17177N17177	Stephenson County, IL	Stephenson County	62100	14250	16250	18300	20300	21950	23550	25200	26800	9999	Stephenson County	Illinois	0
IL	1717999999	17	179	METRO37900M37900	Peoria, IL MSA	Tazewell County	79600	16750	19150	21550	23900	25850	27750	29650	31550	6120	Tazewell County	Illinois	1
IL	1718199999	17	181	NCNTY17181N17181	Union County, IL	Union County	58600	14250	16250	18300	20300	21950	23550	25200	26800	9999	Union County	Illinois	0
IL	1718399999	17	183	METRO19180M19180	Danville, IL MSA	Vermilion County	55600	14250	16250	18300	20300	21950	23550	25200	26800	9999	Vermilion County	Illinois	1
IL	1718599999	17	185	NCNTY17185N17185	Wabash County, IL	Wabash County	69000	14500	16600	18650	20700	22400	24050	25700	27350	9999	Wabash County	Illinois	0
IL	1718799999	17	187	NCNTY17187N17187	Warren County, IL	Warren County	63400	14250	16250	18300	20300	21950	23550	25200	26800	9999	Warren County	Illinois	0
IL	1718999999	17	189	NCNTY17189N17189	Washington County, IL	Washington County	74300	15650	17850	20100	22300	24100	25900	27700	29450	9999	Washington County	Illinois	0
IL	1719199999	17	191	NCNTY17191N17191	Wayne County, IL	Wayne County	60600	14250	16250	18300	20300	21950	23550	25200	26800	9999	Wayne County	Illinois	0
IL	1719399999	17	193	NCNTY17193N17193	White County, IL	White County	62200	14250	16250	18300	20300	21950	23550	25200	26800	9999	White County	Illinois	0
IL	1719599999	17	195	NCNTY17195N17195	Whiteside County, IL	Whiteside County	68100	14350	16400	18450	20450	22100	23750	25400	27000	9999	Whiteside County	Illinois	0
IL	1719799999	17	197	METRO16980M16980	Chicago-Joliet-Naperville, IL HUD Metro FMR Area	Will County	91000	19150	21850	24600	27300	29500	31700	33900	36050	1600	Will County	Illinois	1
IL	1719999999	17	199	METRO16060N17199	Williamson County, IL HUD Metro FMR Area	Williamson County	73000	15350	17550	19750	21900	23700	25450	27200	28950	9999	Williamson County	Illinois	1
IL	1720199999	17	201	METRO40420M40420	Rockford, IL MSA	Winnebago County	69600	14650	16750	18850	20900	22600	24250	25950	27600	6880	Winnebago County	Illinois	1
IL	1720399999	17	203	METRO37900M37900	Peoria, IL MSA	Woodford County	79600	16750	19150	21550	23900	25850	27750	29650	31550	6120	Woodford County	Illinois	1
IN	1800199999	18	1	NCNTY18001N18001	Adams County, IN	Adams County	64800	13750	15700	17650	19600	21200	22750	24350	25900	2760	Adams County	Indiana	0
IN	1800399999	18	3	METRO23060M23060	Fort Wayne, IN MSA	Allen County	71100	14950	17100	19250	21350	23100	24800	26500	28200	2760	Allen County	Indiana	1
IN	1800599999	18	5	METRO18020M18020	Columbus, IN MSA	Bartholomew County	81300	16350	18700	21050	23350	25250	27100	29000	30850	9999	Bartholomew County	Indiana	1
IN	1800799999	18	7	METRO29200M29140	Lafayette-West Lafayette, IN HUD Metro FMR Area	Benton County	79100	15950	18200	20500	22750	24600	26400	28250	30050	9999	Benton County	Indiana	1
IN	1800999999	18	9	NCNTY18009N18009	Blackford County, IN	Blackford County	55000	13750	15700	17650	19600	21200	22750	24350	25900	9999	Blackford County	Indiana	0
IN	1801199999	18	11	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Boone County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Boone County	Indiana	1
IN	1801399999	18	13	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Brown County	82000	17250	19700	22150	24600	26600	28550	30550	32500	9999	Brown County	Indiana	1
IN	1801599999	18	15	METRO29200N18015	Carroll County, IN HUD Metro FMR Area	Carroll County	67400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Carroll County	Indiana	1
IN	1801799999	18	17	NCNTY18017N18017	Cass County, IN	Cass County	60500	13750	15700	17650	19600	21200	22750	24350	25900	9999	Cass County	Indiana	0
IN	1801999999	18	19	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Clark County	77500	16300	18600	20950	23250	25150	27000	28850	30700	4520	Clark County	Indiana	1
IN	1802199999	18	21	METRO45460M45460	Terre Haute, IN HUD Metro FMR Area	Clay County	63900	13750	15700	17650	19600	21200	22750	24350	25900	8320	Clay County	Indiana	1
IN	1802399999	18	23	NCNTY18023N18023	Clinton County, IN	Clinton County	66800	14050	16050	18050	20050	21700	23300	24900	26500	3920	Clinton County	Indiana	0
IN	1802599999	18	25	NCNTY18025N18025	Crawford County, IN	Crawford County	52900	13750	15700	17650	19600	21200	22750	24350	25900	9999	Crawford County	Indiana	0
IN	1802799999	18	27	NCNTY18027N18027	Daviess County, IN	Daviess County	63700	13750	15700	17650	19600	21200	22750	24350	25900	9999	Daviess County	Indiana	0
IN	1802999999	18	29	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Dearborn County	86300	18150	20750	23350	25900	28000	30050	32150	34200	1640	Dearborn County	Indiana	1
IN	1803199999	18	31	NCNTY18031N18031	Decatur County, IN	Decatur County	64400	13750	15700	17650	19600	21200	22750	24350	25900	9999	Decatur County	Indiana	0

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IN	1803399999	18	33	NCNTY18033N18033	DeKalb County, IN	DeKalb County	66600	14000	16000	18000	20000	21600	23200	24800	26400	2760	DeKalb County	Indiana	0
IN	1803599999	18	35	METRO34620M34620	Muncie, IN MSA	Delaware County	64600	13750	15700	17650	19600	21200	22750	24350	25900	5280	Delaware County	Indiana	1
IN	1803799999	18	37	NCNTY18037N18037	Dubois County, IN	Dubois County	77900	16350	18700	21050	23350	25250	27100	29000	30850	9999	Dubois County	Indiana	0
IN	1803999999	18	39	METRO21140M21140	Elkhart-Goshen, IN MSA	Elkhart County	70200	14750	16850	18950	21050	22750	24450	26150	27800	2330	Elkhart County	Indiana	1
IN	1804199999	18	41	NCNTY18041N18041	Fayette County, IN	Fayette County	53700	13750	15700	17650	19600	21200	22750	24350	25900	9999	Fayette County	Indiana	0
IN	1804399999	18	43	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Floyd County	77500	16300	18600	20950	23250	25150	27000	28850	30700	4520	Floyd County	Indiana	1
IN	1804599999	18	45	NCNTY18045N18045	Fountain County, IN	Fountain County	59600	13750	15700	17650	19600	21200	22750	24350	25900	9999	Fountain County	Indiana	0
IN	1804799999	18	47	NCNTY18047N18047	Franklin County, IN	Franklin County	69500	14600	16700	18800	20850	22550	24200	25900	27550	9999	Franklin County	Indiana	0
IN	1804999999	18	49	NCNTY18049N18049	Fulton County, IN	Fulton County	62100	13750	15700	17650	19600	21200	22750	24350	25900	9999	Fulton County	Indiana	0
IN	1805199999	18	51	NCNTY18051N18051	Gibson County, IN	Gibson County	68300	14350	16400	18450	20500	22150	23800	25450	27100	9999	Gibson County	Indiana	0
IN	1805399999	18	53	NCNTY18053N18053	Grant County, IN	Grant County	58500	13750	15700	17650	19600	21200	22750	24350	25900	9999	Grant County	Indiana	0
IN	1805599999	18	55	NCNTY18055N18055	Greene County, IN	Greene County	64700	13750	15700	17650	19600	21200	22750	24350	25900	9999	Greene County	Indiana	0
IN	1805799999	18	57	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Hamilton County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Hamilton County	Indiana	1
IN	1805999999	18	59	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Hancock County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Hancock County	Indiana	1
IN	1806199999	18	61	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Harrison County	77500	16300	18600	20950	23250	25150	27000	28850	30700	4520	Harrison County	Indiana	1
IN	1806399999	18	63	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Hendricks County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Hendricks County	Indiana	1
IN	1806599999	18	65	NCNTY18065N18065	Henry County, IN	Henry County	60600	13750	15700	17650	19600	21200	22750	24350	25900	9999	Henry County	Indiana	0
IN	1806799999	18	67	METRO29020M29020	Kokomo, IN MSA	Howard County	63900	13750	15700	17650	19600	21200	22750	24350	25900	3850	Howard County	Indiana	1
IN	1806999999	18	69	NCNTY18069N18069	Huntington County, IN	Huntington County	64800	13750	15700	17650	19600	21200	22750	24350	25900	2760	Huntington County	Indiana	0
IN	1807199999	18	71	NCNTY18071N18071	Jackson County, IN	Jackson County	64300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Jackson County	Indiana	0
IN	1807399999	18	73	METRO16980N18073	Jasper County, IN HUD Metro FMR Area	Jasper County	69000	14500	16600	18650	20700	22400	24050	25700	27350	9999	Jasper County	Indiana	1
IN	1807599999	18	75	NCNTY18075N18075	Jay County, IN	Jay County	58800	13750	15700	17650	19600	21200	22750	24350	25900	9999	Jay County	Indiana	0
IN	1807799999	18	77	NCNTY18077N18077	Jefferson County, IN	Jefferson County	64100	13750	15700	17650	19600	21200	22750	24350	25900	9999	Jefferson County	Indiana	0
IN	1807999999	18	79	NCNTY18079N18079	Jennings County, IN	Jennings County	61300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Jennings County	Indiana	0
IN	1808199999	18	81	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Johnson County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Johnson County	Indiana	1
IN	1808399999	18	83	NCNTY18083N18083	Knox County, IN	Knox County	60000	13750	15700	17650	19600	21200	22750	24350	25900	9999	Knox County	Indiana	0
IN	1808599999	18	85	NCNTY18085N18085	Kosciusko County, IN	Kosciusko County	74700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Kosciusko County	Indiana	0
IN	1808799999	18	87	NCNTY18087N18087	LaGrange County, IN	LaGrange County	67700	14250	16250	18300	20300	21950	23550	25200	26800	9999	LaGrange County	Indiana	0
IN	1808999999	18	89	METRO16980MM2960	Gary, IN HUD Metro FMR Area	Lake County	74900	15750	18000	20250	22450	24250	26050	27850	29650	2960	Lake County	Indiana	1
IN	1809199999	18	91	METRO33140M33140	Michigan City-La Porte, IN MSA	LaPorte County	65200	13750	15700	17650	19600	21200	22750	24350	25900	9999	LaPorte County	Indiana	1
IN	1809399999	18	93	NCNTY18093N18093	Lawrence County, IN	Lawrence County	62800	13750	15700	17650	19600	21200	22750	24350	25900	9999	Lawrence County	Indiana	0
IN	1809599999	18	95	METRO26900M11300	Anderson, IN HUD Metro FMR Area	Madison County	58000	13750	15700	17650	19600	21200	22750	24350	25900	3480	Madison County	Indiana	1
IN	1809799999	18	97	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Marion County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Marion County	Indiana	1
IN	1809999999	18	99	NCNTY18099N18099	Marshall County, IN	Marshall County	65900	13850	15800	17800	19750	21350	22950	24500	26100	9999	Marshall County	Indiana	0
IN	1810199999	18	101	NCNTY18101N18101	Martin County, IN	Martin County	63100	13750	15700	17650	19600	21200	22750	24350	25900	9999	Martin County	Indiana	0
IN	1810399999	18	103	NCNTY18103N18103	Miami County, IN	Miami County	61400	13750	15700	17650	19600	21200	22750	24350	25900	9999	Miami County	Indiana	0
IN	1810599999	18	105	METRO14020MM1020	Bloomington, IN HUD Metro FMR Area	Monroe County	74900	15750	18000	20250	22450	24250	26050	27850	29650	1020	Monroe County	Indiana	1
IN	1810799999	18	107	NCNTY18107N18107	Montgomery County, IN	Montgomery County	67900	14250	16300	18350	20350	22000	23650	25250	26900	9999	Montgomery County	Indiana	0
IN	1810999999	18	109	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Morgan County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Morgan County	Indiana	1
IN	1811199999	18	111	METRO16980MM2960	Gary, IN HUD Metro FMR Area	Newton County	74900	15750	18000	20250	22450	24250	26050	27850	29650	9999	Newton County	Indiana	1
IN	1811399999	18	113	NCNTY18113N18113	Noble County, IN	Noble County	67400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Noble County	Indiana	0
IN	1811599999	18	115	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Ohio County	86300	18150	20750	23350	25900	28000	30050	32150	34200	5840	Ohio County	Indiana	1
IN	1811799999	18	117	NCNTY18117N18117	Orange County, IN	Orange County	57100	13750	15700	17650	19600	21200	22750	24350	25900	9999	Orange County	Indiana	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
IN	1811999999	18	119	METRO14020N18119	Owen County, IN HUD Metro FMR Area	Owen County	64300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Owen County	Indiana	1
IN	1812199999	18	121	NCNTY18121N18121	Parke County, IN	Parke County	56800	13750	15700	17650	19600	21200	22750	24350	25900	9999	Parke County	Indiana	0
IN	1812399999	18	123	NCNTY18123N18123	Perry County, IN	Perry County	64600	13750	15700	17650	19600	21200	22750	24350	25900	9999	Perry County	Indiana	0
IN	1812599999	18	125	NCNTY18125N18125	Pike County, IN	Pike County	65800	13850	15800	17800	19750	21350	22950	24500	26100	9999	Pike County	Indiana	0
IN	1812799999	18	127	METRO16980MM2960	Gary, IN HUD Metro FMR Area	Porter County	74900	15750	18000	20250	22450	24250	26050	27850	29650	2960	Porter County	Indiana	1
IN	1812999999	18	129	METRO21780M21780	Evansville, IN-KY MSA	Posey County	74800	15250	17400	19600	21750	23500	25250	27000	28750	2440	Posey County	Indiana	1
IN	1813199999	18	131	NCNTY18131N18131	Pulaski County, IN	Pulaski County	59400	13750	15700	17650	19600	21200	22750	24350	25900	9999	Pulaski County	Indiana	0
IN	1813399999	18	133	METRO26900N18133	Putnam County, IN HUD Metro FMR Area	Putnam County	70100	14750	16850	18950	21050	22750	24450	26150	27800	9999	Putnam County	Indiana	1
IN	1813599999	18	135	NCNTY18135N18135	Randolph County, IN	Randolph County	59400	13750	15700	17650	19600	21200	22750	24350	25900	9999	Randolph County	Indiana	0
IN	1813799999	18	137	NCNTY18137N18137	Ripley County, IN	Ripley County	66600	14000	16000	18000	20000	21600	23200	24800	26400	9999	Ripley County	Indiana	0
IN	1813999999	18	139	NCNTY18139N18139	Rush County, IN	Rush County	62600	13750	15700	17650	19600	21200	22750	24350	25900	9999	Rush County	Indiana	0
IN	1814199999	18	141	METRO43780M43780	South Bend-Mishawaka, IN HUD Metro FMR Area	St. Joseph County	70800	14900	17000	19150	21250	22950	24650	26350	28050	7800	St. Joseph County	Indiana	1
IN	1814399999	18	143	METRO31140N18143	Scott County, IN HUD Metro FMR Area	Scott County	61600	13750	15700	17650	19600	21200	22750	24350	25900	4520	Scott County	Indiana	1
IN	1814599999	18	145	METRO26900M26900	Indianapolis-Carmel, IN HUD Metro FMR Area	Shelby County	82000	17250	19700	22150	24600	26600	28550	30550	32500	3480	Shelby County	Indiana	1
IN	1814799999	18	147	NCNTY18147N18147	Spencer County, IN	Spencer County	73500	15450	17650	19850	22050	23850	25600	27350	29150	9999	Spencer County	Indiana	0
IN	1814999999	18	149	NCNTY18149N18149	Starke County, IN	Starke County	58100	13750	15700	17650	19600	21200	22750	24350	25900	9999	Starke County	Indiana	0
IN	1815199999	18	151	NCNTY18151N18151	Steuben County, IN	Steuben County	66400	13950	15950	17950	19900	21500	23100	24700	26300	9999	Steuben County	Indiana	0
IN	1815399999	18	153	METRO45460N18153	Sullivan County, IN HUD Metro FMR Area	Sullivan County	60900	13750	15700	17650	19600	21200	22750	24350	25900	9999	Sullivan County	Indiana	1
IN	1815599999	18	155	NCNTY18155N18155	Switzerland County, IN	Switzerland County	53700	13750	15700	17650	19600	21200	22750	24350	25900	9999	Switzerland County	Indiana	0
IN	1815799999	18	157	METRO29200M29140	Lafayette-West Lafayette, IN HUD Metro FMR Area	Tippecanoe County	79100	15950	18200	20500	22750	24600	26400	28250	30050	3920	Tippecanoe County	Indiana	1
IN	1815999999	18	159	NCNTY18159N18159	Tipton County, IN	Tipton County	70900	14900	17000	19150	21250	22950	24650	26350	28050	3850	Tipton County	Indiana	0
IN	1816199999	18	161	METRO17140N18161	Union County, IN HUD Metro FMR Area	Union County	61300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Union County	Indiana	1
IN	1816399999	18	163	METRO21780M21780	Evansville, IN-KY MSA	Vanderburgh County	74800	15250	17400	19600	21750	23500	25250	27000	28750	2440	Vanderburgh County	Indiana	1
IN	1816599999	18	165	METRO45460M45460	Terre Haute, IN HUD Metro FMR Area	Vermillion County	63900	13750	15700	17650	19600	21200	22750	24350	25900	8320	Vermillion County	Indiana	1
IN	1816799999	18	167	METRO45460M45460	Terre Haute, IN HUD Metro FMR Area	Vigo County	63900	13750	15700	17650	19600	21200	22750	24350	25900	8320	Vigo County	Indiana	1
IN	1816999999	18	169	NCNTY18169N18169	Wabash County, IN	Wabash County	62200	13750	15700	17650	19600	21200	22750	24350	25900	9999	Wabash County	Indiana	0
IN	1817199999	18	171	NCNTY18171N18171	Warren County, IN	Warren County	69500	14600	16700	18800	20850	22550	24200	25900	27550	9999	Warren County	Indiana	0
IN	1817399999	18	173	METRO21780M21780	Evansville, IN-KY MSA	Warrick County	74800	15250	17400	19600	21750	23500	25250	27000	28750	2440	Warrick County	Indiana	1
IN	1817599999	18	175	METRO31140N18175	Washington County, IN HUD Metro FMR Area	Washington County	60400	13750	15700	17650	19600	21200	22750	24350	25900	9999	Washington County	Indiana	1
IN	1817799999	18	177	NCNTY18177N18177	Wayne County, IN	Wayne County	61600	13750	15700	17650	19600	21200	22750	24350	25900	9999	Wayne County	Indiana	0
IN	1817999999	18	179	METRO23060M23060	Fort Wayne, IN MSA	Wells County	71100	14950	17100	19250	21350	23100	24800	26500	28200	2760	Wells County	Indiana	1
IN	1818199999	18	181	NCNTY18181N18181	White County, IN	White County	66200	13900	15900	17900	19850	21450	23050	24650	26250	9999	White County	Indiana	0
IN	1818399999	18	183	METRO23060M23060	Fort Wayne, IN MSA	Whitley County	71100	14950	17100	19250	21350	23100	24800	26500	28200	2760	Whitley County	Indiana	1
IA	1900199999	19	1	NCNTY19001N19001	Adair County, IA	Adair County	66600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Adair County	Iowa	0
IA	1900399999	19	3	NCNTY19003N19003	Adams County, IA	Adams County	65700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Adams County	Iowa	0
IA	1900599999	19	5	NCNTY19005N19005	Allamakee County, IA	Allamakee County	68400	15250	17400	19600	21750	23500	25250	27000	28750	9999	Allamakee County	Iowa	0
IA	1900799999	19	7	NCNTY19007N19007	Appanoose County, IA	Appanoose County	57200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Appanoose County	Iowa	0
IA	1900999999	19	9	NCNTY19009N19009	Audubon County, IA	Audubon County	65700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Audubon County	Iowa	0
IA	1901199999	19	11	METRO16300N19011	Benton County, IA HUD Metro FMR Area	Benton County	85100	17900	20450	23000	25550	27600	29650	31700	33750	9999	Benton County	Iowa	1
IA	1901399999	19	13	METRO47940M47940	Waterloo-Cedar Falls, IA HUD Metro FMR Area	Black Hawk County	71600	15250	17400	19600	21750	23500	25250	27000	28750	8920	Black Hawk County	Iowa	1
IA	1901599999	19	15	NCNTY19015N19015	Boone County, IA	Boone County	77700	16350	18650	21000	23300	25200	27050	28900	30800	9999	Boone County	Iowa	0
IA	1901799999	19	17	METRO47940N19017	Bremer County, IA HUD Metro FMR Area	Bremer County	87600	18450	21050	23700	26300	28450	30550	32650	34750	9999	Bremer County	Iowa	1
IA	1901999999	19	19	NCNTY19019N19019	Buchanan County, IA	Buchanan County	79200	16650	19000	21400	23750	25650	27550	29450	31350	9999	Buchanan County	Iowa	0
IA	1902199999	19	21	NCNTY19021N19021	Buena Vista County, IA	Buena Vista County	68600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Buena Vista County	Iowa	0
IA	1902399999	19	23	NCNTY19023N19023	Butler County, IA	Butler County	71600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Butler County	Iowa	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
IA	1902599999	19	25	NCNTY19025N19025	Calhoun County, IA	Calhoun County	63000	15250	17400	19600	21750	23500	25250	27000	28750	9999	Calhoun County	Iowa	0
IA	1902799999	19	27	NCNTY19027N19027	Carroll County, IA	Carroll County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Carroll County	Iowa	0
IA	1902999999	19	29	NCNTY19029N19029	Cass County, IA	Cass County	61600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Cass County	Iowa	0
IA	1903199999	19	31	NCNTY19031N19031	Cedar County, IA	Cedar County	82500	17350	19800	22300	24750	26750	28750	30700	32700	9999	Cedar County	Iowa	0
IA	1903399999	19	33	NCNTY19033N19033	Cerro Gordo County, IA	Cerro Gordo County	71700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Cerro Gordo County	Iowa	0
IA	1903599999	19	35	NCNTY19035N19035	Cherokee County, IA	Cherokee County	73200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Cherokee County	Iowa	0
IA	1903799999	19	37	NCNTY19037N19037	Chickasaw County, IA	Chickasaw County	73200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Chickasaw County	Iowa	0
IA	1903999999	19	39	NCNTY19039N19039	Clarke County, IA	Clarke County	66000	15250	17400	19600	21750	23500	25250	27000	28750	9999	Clarke County	Iowa	0
IA	1904199999	19	41	NCNTY19041N19041	Clay County, IA	Clay County	68500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Clay County	Iowa	0
IA	1904399999	19	43	NCNTY19043N19043	Clayton County, IA	Clayton County	69500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Clayton County	Iowa	0
IA	1904599999	19	45	NCNTY19045N19045	Clinton County, IA	Clinton County	71700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Clinton County	Iowa	0
IA	1904799999	19	47	NCNTY19047N19047	Crawford County, IA	Crawford County	63100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Crawford County	Iowa	0
IA	1904999999	19	49	METRO19780M19780	Des Moines-West Des Moines, IA MSA	Dallas County	89200	18750	21400	24100	26750	28900	31050	33200	35350	2120	Dallas County	Iowa	1
IA	1905199999	19	51	NCNTY19051N19051	Davis County, IA	Davis County	71000	15250	17400	19600	21750	23500	25250	27000	28750	9999	Davis County	Iowa	0
IA	1905399999	19	53	NCNTY19053N19053	Decatur County, IA	Decatur County	53500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Decatur County	Iowa	0
IA	1905599999	19	55	NCNTY19055N19055	Delaware County, IA	Delaware County	76900	16150	18450	20750	23050	24900	26750	28600	30450	9999	Delaware County	Iowa	0
IA	1905799999	19	57	NCNTY19057N19057	Des Moines County, IA	Des Moines County	64700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Des Moines County	Iowa	0
IA	1905999999	19	59	NCNTY19059N19059	Dickinson County, IA	Dickinson County	83400	17500	20000	22500	25000	27000	29000	31000	33000	9999	Dickinson County	Iowa	0
IA	1906199999	19	61	METRO20220M20220	Dubuque, IA MSA	Dubuque County	82900	17400	19900	22400	24850	26850	28850	30850	32850	2200	Dubuque County	Iowa	1
IA	1906399999	19	63	NCNTY19063N19063	Emmet County, IA	Emmet County	71600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Emmet County	Iowa	0
IA	1906599999	19	65	NCNTY19065N19065	Fayette County, IA	Fayette County	63900	15250	17400	19600	21750	23500	25250	27000	28750	9999	Fayette County	Iowa	0
IA	1906799999	19	67	NCNTY19067N19067	Floyd County, IA	Floyd County	67100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Floyd County	Iowa	0
IA	1906999999	19	69	NCNTY19069N19069	Franklin County, IA	Franklin County	61200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Franklin County	Iowa	0
IA	1907199999	19	71	NCNTY19071N19071	Fremont County, IA	Fremont County	70100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Fremont County	Iowa	0
IA	1907399999	19	73	NCNTY19073N19073	Greene County, IA	Greene County	71100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Greene County	Iowa	0
IA	1907599999	19	75	METRO47940M47940	Waterloo-Cedar Falls, IA HUD Metro FMR Area	Grundy County	71600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Grundy County	Iowa	1
IA	1907799999	19	77	METRO19780M19780	Des Moines-West Des Moines, IA MSA	Guthrie County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Guthrie County	Iowa	1
IA	1907999999	19	79	NCNTY19079N19079	Hamilton County, IA	Hamilton County	73400	15400	17600	19800	22000	23800	25550	27300	29050	9999	Hamilton County	Iowa	0
IA	1908199999	19	81	NCNTY19081N19081	Hancock County, IA	Hancock County	71500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Hancock County	Iowa	0
IA	1908399999	19	83	NCNTY19083N19083	Hardin County, IA	Hardin County	74400	15650	17850	20100	22300	24100	25900	27700	29450	9999	Hardin County	Iowa	0
IA	1908599999	19	85	METRO36540M36540	Omaha-Council Bluffs, NE-IA HUD Metro FMR Area	Harrison County	87000	18300	20900	23500	26100	28200	30300	32400	34500	9999	Harrison County	Iowa	1
IA	1908799999	19	87	NCNTY19087N19087	Henry County, IA	Henry County	66900	15250	17400	19600	21750	23500	25250	27000	28750	9999	Henry County	Iowa	0
IA	1908999999	19	89	NCNTY19089N19089	Howard County, IA	Howard County	66200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Howard County	Iowa	0
IA	1909199999	19	91	NCNTY19091N19091	Humboldt County, IA	Humboldt County	67900	15250	17400	19600	21750	23500	25250	27000	28750	9999	Humboldt County	Iowa	0
IA	1909399999	19	93	NCNTY19093N19093	Ida County, IA	Ida County	73200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Ida County	Iowa	0
IA	1909599999	19	95	NCNTY19095N19095	Iowa County, IA	Iowa County	76400	16050	18350	20650	22900	24750	26600	28400	30250	9999	Iowa County	Iowa	0
IA	1909799999	19	97	NCNTY19097N19097	Jackson County, IA	Jackson County	66300	15250	17400	19600	21750	23500	25250	27000	28750	9999	Jackson County	Iowa	0
IA	1909999999	19	99	NCNTY19099N19099	Jasper County, IA	Jasper County	72800	15300	17500	19700	21850	23600	25350	27100	28850	9999	Jasper County	Iowa	0
IA	1910199999	19	101	NCNTY19101N19101	Jefferson County, IA	Jefferson County	66200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Jefferson County	Iowa	0
IA	1910399999	19	103	METRO26980MM3500	Iowa City, IA HUD Metro FMR Area	Johnson County	101200	21250	24300	27350	30350	32800	35250	37650	40100	3500	Johnson County	Iowa	1
IA	1910599999	19	105	METRO16300N19105	Jones County, IA HUD Metro FMR Area	Jones County	76200	16000	18300	20600	22850	24700	26550	28350	30200	9999	Jones County	Iowa	1
IA	1910799999	19	107	NCNTY19107N19107	Keokuk County, IA	Keokuk County	69200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Keokuk County	Iowa	0
IA	1910999999	19	109	NCNTY19109N19109	Kossuth County, IA	Kossuth County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Kossuth County	Iowa	0
IA	1911199999	19	111	NCNTY19111N19111	Lee County, IA	Lee County	64400	15250	17400	19600	21750	23500	25250	27000	28750	9999	Lee County	Iowa	0
IA	1911399999	19	113	METRO16300M16300	Cedar Rapids, IA HUD Metro FMR Area	Linn County	85200	17900	20450	23000	25550	27600	29650	31700	33750	1360	Linn County	Iowa	1
IA	1911599999	19	115	NCNTY19115N19115	Louisa County, IA	Louisa County	71800	15250	17400	19600	21750	23500	25250	27000	28750	9999	Louisa County	Iowa	0
IA	1911799999	19	117	NCNTY19117N19117	Lucas County, IA	Lucas County	67100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Lucas County	Iowa	0
IA	1911999999	19	119	NCNTY19119N19119	Lyon County, IA	Lyon County	74200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Lyon County	Iowa	0
IA	1912199999	19	121	METRO19780M19780	Des Moines-West Des Moines, IA MSA	Madison County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Madison County	Iowa	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
IA	1912399999	19	123	NCNTY19123N19123	Mahaska County, IA	Mahaska County	65100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Mahaska County	Iowa	0
IA	1912599999	19	125	NCNTY19125N19125	Marion County, IA	Marion County	76400	16050	18350	20650	22900	24750	26600	28400	30250	9999	Marion County	Iowa	0
IA	1912799999	19	127	NCNTY19127N19127	Marshall County, IA	Marshall County	67200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Marshall County	Iowa	0
IA	1912999999	19	129	METRO36540M36540	Omaha-Council Bluffs, NE-IA HUD Metro FMR Area	Mills County	87000	18300	20900	23500	26100	28200	30300	32400	34500	9999	Mills County	Iowa	1
IA	1913199999	19	131	NCNTY19131N19131	Mitchell County, IA	Mitchell County	70700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Mitchell County	Iowa	0
IA	1913399999	19	133	NCNTY19133N19133	Monona County, IA	Monona County	63900	15250	17400	19600	21750	23500	25250	27000	28750	9999	Monona County	Iowa	0
IA	1913599999	19	135	NCNTY19135N19135	Monroe County, IA	Monroe County	66900	15250	17400	19600	21750	23500	25250	27000	28750	9999	Monroe County	Iowa	0
IA	1913799999	19	137	NCNTY19137N19137	Montgomery County, IA	Montgomery County	59300	15250	17400	19600	21750	23500	25250	27000	28750	9999	Montgomery County	Iowa	0
IA	1913999999	19	139	NCNTY19139N19139	Muscatine County, IA	Muscatine County	73100	15400	17600	19800	21950	23750	25500	27250	29000	9999	Muscatine County	Iowa	0
IA	1914199999	19	141	NCNTY19141N19141	O'Brien County, IA	O'Brien County	76300	16050	18350	20650	22900	24750	26600	28400	30250	9999	O'Brien County	Iowa	0
IA	1914399999	19	143	NCNTY19143N19143	Osceola County, IA	Osceola County	68700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Osceola County	Iowa	0
IA	1914599999	19	145	NCNTY19145N19145	Page County, IA	Page County	64900	15250	17400	19600	21750	23500	25250	27000	28750	9999	Page County	Iowa	0
IA	1914799999	19	147	NCNTY19147N19147	Palo Alto County, IA	Palo Alto County	71200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Palo Alto County	Iowa	0
IA	1914999999	19	149	METRO43580N19149	Plymouth County, IA HUD Metro FMR Area	Plymouth County	79100	16650	19000	21400	23750	25650	27550	29450	31350	9999	Plymouth County	Iowa	1
IA	1915199999	19	151	NCNTY19151N19151	Pocahontas County, IA	Pocahontas County	67000	15250	17400	19600	21750	23500	25250	27000	28750	9999	Pocahontas County	Iowa	0
IA	1915399999	19	153	METRO19780M19780	Des Moines-West Des Moines, IA MSA	Polk County	89200	18750	21400	24100	26750	28900	31050	33200	35350	2120	Polk County	Iowa	1
IA	1915599999	19	155	METRO36540M36540	Omaha-Council Bluffs, NE-IA HUD Metro FMR Area	Pottawattamie County	87000	18300	20900	23500	26100	28200	30300	32400	34500	5920	Pottawattamie County	Iowa	1
IA	1915799999	19	157	NCNTY19157N19157	Poweshiek County, IA	Poweshiek County	73000	15350	17550	19750	21900	23700	25450	27200	28950	9999	Poweshiek County	Iowa	0
IA	1915999999	19	159	NCNTY19159N19159	Ringgold County, IA	Ringgold County	62200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Ringgold County	Iowa	0
IA	1916199999	19	161	NCNTY19161N19161	Sac County, IA	Sac County	71000	15250	17400	19600	21750	23500	25250	27000	28750	9999	Sac County	Iowa	0
IA	1916399999	19	163	METRO19340M19340	Davenport-Moline-Rock Island, IA-IL MSA	Scott County	75400	15850	18100	20350	22600	24450	26250	28050	29850	1960	Scott County	Iowa	1
IA	1916599999	19	165	NCNTY19165N19165	Shelby County, IA	Shelby County	72500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Shelby County	Iowa	0
IA	1916799999	19	167	NCNTY19167N19167	Sioux County, IA	Sioux County	80600	16950	19400	21800	24200	26150	28100	30050	31950	9999	Sioux County	Iowa	0
IA	1916999999	19	169	METRO11180M11180	Ames, IA MSA	Story County	104300	19900	22750	25600	28400	30700	32950	35250	37500	9999	Story County	Iowa	1
IA	1917199999	19	171	NCNTY19171N19171	Tama County, IA	Tama County	71600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Tama County	Iowa	0
IA	1917399999	19	173	NCNTY19173N19173	Taylor County, IA	Taylor County	62400	15250	17400	19600	21750	23500	25250	27000	28750	9999	Taylor County	Iowa	0
IA	1917599999	19	175	NCNTY19175N19175	Union County, IA	Union County	66800	15250	17400	19600	21750	23500	25250	27000	28750	9999	Union County	Iowa	0
IA	1917799999	19	177	NCNTY19177N19177	Van Buren County, IA	Van Buren County	64600	15250	17400	19600	21750	23500	25250	27000	28750	9999	Van Buren County	Iowa	0
IA	1917999999	19	179	NCNTY19179N19179	Wapello County, IA	Wapello County	58700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Wapello County	Iowa	0
IA	1918199999	19	181	METRO19780M19780	Des Moines-West Des Moines, IA MSA	Warren County	89200	18750	21400	24100	26750	28900	31050	33200	35350	2120	Warren County	Iowa	1
IA	1918399999	19	183	METRO26980N19183	Washington County, IA HUD Metro FMR Area	Washington County	78200	16450	18800	21150	23450	25350	27250	29100	31000	9999	Washington County	Iowa	1
IA	1918599999	19	185	NCNTY19185N19185	Wayne County, IA	Wayne County	58200	15250	17400	19600	21750	23500	25250	27000	28750	9999	Wayne County	Iowa	0
IA	1918799999	19	187	NCNTY19187N19187	Webster County, IA	Webster County	62700	15250	17400	19600	21750	23500	25250	27000	28750	9999	Webster County	Iowa	0
IA	1918999999	19	189	NCNTY19189N19189	Winnebago County, IA	Winnebago County	67100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Winnebago County	Iowa	0
IA	1919199999	19	191	NCNTY19191N19191	Winneshiek County, IA	Winneshiek County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Winneshiek County	Iowa	0
IA	1919399999	19	193	METRO43580M43580	Sioux City, IA-NE-SD HUD Metro FMR Area	Woodbury County	75200	15750	18000	20250	22500	24300	26100	27900	29700	7720	Woodbury County	Iowa	1
IA	1919599999	19	195	NCNTY19195N19195	Worth County, IA	Worth County	68100	15250	17400	19600	21750	23500	25250	27000	28750	9999	Worth County	Iowa	0
IA	1919799999	19	197	NCNTY19197N19197	Wright County, IA	Wright County	64000	15250	17400	19600	21750	23500	25250	27000	28750	9999	Wright County	Iowa	0
KS	2000199999	20	1	NCNTY20001N20001	Allen County, KS	Allen County	61600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Allen County	Kansas	0
KS	2000399999	20	3	NCNTY20003N20003	Anderson County, KS	Anderson County	61100	13600	15550	17500	19400	21000	22550	24100	25650	9999	Anderson County	Kansas	0
KS	2000599999	20	5	NCNTY20005N20005	Atchison County, KS	Atchison County	61900	13600	15550	17500	19400	21000	22550	24100	25650	9999	Atchison County	Kansas	0
KS	2000799999	20	7	NCNTY20007N20007	Barber County, KS	Barber County	73900	14950	17100	19250	21350	23100	24800	26500	28200	9999	Barber County	Kansas	0
KS	2000999999	20	9	NCNTY20009N20009	Barton County, KS	Barton County	66100	13900	15900	17900	19850	21450	23050	24650	26250	9999	Barton County	Kansas	0
KS	2001199999	20	11	NCNTY20011N20011	Bourbon County, KS	Bourbon County	54300	13600	15550	17500	19400	21000	22550	24100	25650	9999	Bourbon County	Kansas	0
KS	2001399999	20	13	NCNTY20013N20013	Brown County, KS	Brown County	57900	13600	15550	17500	19400	21000	22550	24100	25650	9999	Brown County	Kansas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
KS	2001599999	20	15	METRO48620M48620	Wichita, KS HUD Metro FMR Area	Butler County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9040	Butler County	Kansas	1
KS	2001799999	20	17	NCNTY20017N20017	Chase County, KS	Chase County	65200	13700	15650	17600	19550	21150	22700	24250	25850	9999	Chase County	Kansas	0
KS	2001999999	20	19	NCNTY20019N20019	Chautauqua County, KS	Chautauqua County	56900	13600	15550	17500	19400	21000	22550	24100	25650	9999	Chautauqua County	Kansas	0
KS	2002199999	20	21	NCNTY20021N20021	Cherokee County, KS	Cherokee County	56300	13600	15550	17500	19400	21000	22550	24100	25650	9999	Cherokee County	Kansas	0
KS	2002399999	20	23	NCNTY20023N20023	Cheyenne County, KS	Cheyenne County	63700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Cheyenne County	Kansas	0
KS	2002599999	20	25	NCNTY20025N20025	Clark County, KS	Clark County	63500	13600	15550	17500	19400	21000	22550	24100	25650	9999	Clark County	Kansas	0
KS	2002799999	20	27	NCNTY20027N20027	Clay County, KS	Clay County	67800	14250	16300	18350	20350	22000	23650	25250	26900	9999	Clay County	Kansas	0
KS	2002999999	20	29	NCNTY20029N20029	Cloud County, KS	Cloud County	58000	13600	15550	17500	19400	21000	22550	24100	25650	9999	Cloud County	Kansas	0
KS	2003199999	20	31	NCNTY20031N20031	Coffey County, KS	Coffey County	76900	16150	18450	20750	23050	24900	26750	28600	30450	9999	Coffey County	Kansas	0
KS	2003399999	20	33	NCNTY20033N20033	Comanche County, KS	Comanche County	66000	13900	15850	17850	19800	21400	23000	24600	26150	9999	Comanche County	Kansas	0
KS	2003599999	20	35	NCNTY20035N20035	Cowley County, KS	Cowley County	60200	13600	15550	17500	19400	21000	22550	24100	25650	9999	Cowley County	Kansas	0
KS	2003799999	20	37	NCNTY20037N20037	Crawford County, KS	Crawford County	61100	13600	15550	17500	19400	21000	22550	24100	25650	9999	Crawford County	Kansas	0
KS	2003999999	20	39	NCNTY20039N20039	Decatur County, KS	Decatur County	60500	13600	15550	17500	19400	21000	22550	24100	25650	9999	Decatur County	Kansas	0
KS	2004199999	20	41	NCNTY20041N20041	Dickinson County, KS	Dickinson County	64900	13650	15600	17550	19450	21050	22600	24150	25700	9999	Dickinson County	Kansas	0
KS	2004399999	20	43	METRO41140M41140	St. Joseph, MO-KS MSA	Doniphan County	63600	13400	15300	17200	19100	20650	22200	23700	25250	9999	Doniphan County	Kansas	1
KS	2004599999	20	45	METRO29940M29940	Lawrence, KS MSA	Douglas County	88800	18550	21200	23850	26500	28650	30750	32900	35000	4150	Douglas County	Kansas	1
KS	2004799999	20	47	NCNTY20047N20047	Edwards County, KS	Edwards County	61100	13600	15550	17500	19400	21000	22550	24100	25650	9999	Edwards County	Kansas	0
KS	2004999999	20	49	NCNTY20049N20049	Elk County, KS	Elk County	55500	13600	15550	17500	19400	21000	22550	24100	25650	9999	Elk County	Kansas	0
KS	2005199999	20	51	NCNTY20051N20051	Ellis County, KS	Ellis County	77600	16350	18650	21000	23300	25200	27050	28900	30800	9999	Ellis County	Kansas	0
KS	2005399999	20	53	NCNTY20053N20053	Ellsworth County, KS	Ellsworth County	67600	14250	16250	18300	20300	21950	23550	25200	26800	9999	Ellsworth County	Kansas	0
KS	2005599999	20	55	NCNTY20055N20055	Finney County, KS	Finney County	62000	13600	15550	17500	19400	21000	22550	24100	25650	9999	Finney County	Kansas	0
KS	2005799999	20	57	NCNTY20057N20057	Ford County, KS	Ford County	60200	13600	15550	17500	19400	21000	22550	24100	25650	9999	Ford County	Kansas	0
KS	2005999999	20	59	NCNTY20059N20059	Franklin County, KS	Franklin County	70100	14750	16850	18950	21050	22750	24450	26150	27800	9999	Franklin County	Kansas	0
KS	2006199999	20	61	NCNTY20061N20061	Geary County, KS	Geary County	53600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Geary County	Kansas	0
KS	2006399999	20	63	NCNTY20063N20063	Gove County, KS	Gove County	63500	13600	15550	17500	19400	21000	22550	24100	25650	9999	Gove County	Kansas	0
KS	2006599999	20	65	NCNTY20065N20065	Graham County, KS	Graham County	61800	13600	15550	17500	19400	21000	22550	24100	25650	9999	Graham County	Kansas	0
KS	2006799999	20	67	NCNTY20067N20067	Grant County, KS	Grant County	72400	15200	17400	19550	21700	23450	25200	26950	28650	9999	Grant County	Kansas	0
KS	2006999999	20	69	NCNTY20069N20069	Gray County, KS	Gray County	72200	15200	17350	19500	21650	23400	25150	26850	28600	9999	Gray County	Kansas	0
KS	2007199999	20	71	NCNTY20071N20071	Greeley County, KS	Greeley County	65300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Greeley County	Kansas	0
KS	2007399999	20	73	NCNTY20073N20073	Greenwood County, KS	Greenwood County	55700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Greenwood County	Kansas	0
KS	2007599999	20	75	NCNTY20075N20075	Hamilton County, KS	Hamilton County	58700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Hamilton County	Kansas	0
KS	2007799999	20	77	NCNTY20077N20077	Harper County, KS	Harper County	61600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Harper County	Kansas	0
KS	2007999999	20	79	METRO48620M48620	Wichita, KS HUD Metro FMR Area	Harvey County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9040	Harvey County	Kansas	1
KS	2008199999	20	81	NCNTY20081N20081	Haskell County, KS	Haskell County	63100	13600	15550	17500	19400	21000	22550	24100	25650	9999	Haskell County	Kansas	0
KS	2008399999	20	83	NCNTY20083N20083	Hodgeman County, KS	Hodgeman County	72700	15300	17450	19650	21800	23550	25300	27050	28800	9999	Hodgeman County	Kansas	0
KS	2008599999	20	85	METRO45820M45820	Topeka, KS MSA	Jackson County	77700	16350	18650	21000	23300	25200	27050	28900	30800	9999	Jackson County	Kansas	1
KS	2008799999	20	87	METRO45820M45820	Topeka, KS MSA	Jefferson County	77700	16350	18650	21000	23300	25200	27050	28900	30800	9999	Jefferson County	Kansas	1
KS	2008999999	20	89	NCNTY20089N20089	Jewell County, KS	Jewell County	56300	13600	15550	17500	19400	21000	22550	24100	25650	9999	Jewell County	Kansas	0
KS	2009199999	20	91	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Johnson County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Johnson County	Kansas	1
KS	2009399999	20	93	NCNTY20093N20093	Kearny County, KS	Kearny County	69400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Kearny County	Kansas	0
KS	2009599999	20	95	METRO48620N20095	Kingman County, KS HUD Metro FMR Area	Kingman County	74300	15650	17850	20100	22300	24100	25900	27700	29450	9999	Kingman County	Kansas	1
KS	2009799999	20	97	NCNTY20097N20097	Kiowa County, KS	Kiowa County	66600	14000	16000	18000	20000	21600	23200	24800	26400	9999	Kiowa County	Kansas	0
KS	2009999999	20	99	NCNTY20099N20099	Labette County, KS	Labette County	59100	13600	15550	17500	19400	21000	22550	24100	25650	9999	Labette County	Kansas	0
KS	2010199999	20	101	NCNTY20101N20101	Lane County, KS	Lane County	72500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Lane County	Kansas	0
KS	2010399999	20	103	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Leavenworth County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Leavenworth County	Kansas	1
KS	2010599999	20	105	NCNTY20105N20105	Lincoln County, KS	Lincoln County	67200	14150	16150	18150	20150	21800	23400	25000	26600	9999	Lincoln County	Kansas	0
KS	2010799999	20	107	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Linn County	86000	18100	20650	23250	25800	27900	29950	32000	34100	9999	Linn County	Kansas	1
KS	2010999999	20	109	NCNTY20109N20109	Logan County, KS	Logan County	70600	14850	17000	19100	21200	22900	24600	26300	28000	9999	Logan County	Kansas	0
KS	2011199999	20	111	NCNTY20111N20111	Lyon County, KS	Lyon County	60800	13600	15550	17500	19400	21000	22550	24100	25650	9999	Lyon County	Kansas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
KS	2011399999	20	113	NCNTY20113N20113	McPherson County, KS	McPherson County	72900	15300	17500	19700	21850	23600	25350	27100	28850	9999	McPherson County	Kansas	0
KS	2011599999	20	115	NCNTY20115N20115	Marion County, KS	Marion County	66500	14000	16000	18000	19950	21550	23150	24750	26350	9999	Marion County	Kansas	0
KS	2011799999	20	117	NCNTY20117N20117	Marshall County, KS	Marshall County	66600	14000	16000	18000	20000	21600	23200	24800	26400	9999	Marshall County	Kansas	0
KS	2011999999	20	119	NCNTY20119N20119	Meade County, KS	Meade County	66200	13900	15900	17900	19850	21450	23050	24650	26250	9999	Meade County	Kansas	0
KS	2012199999	20	121	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Miami County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Miami County	Kansas	1
KS	2012399999	20	123	NCNTY20123N20123	Mitchell County, KS	Mitchell County	66800	14050	16050	18050	20050	21700	23300	24900	26500	9999	Mitchell County	Kansas	0
KS	2012599999	20	125	NCNTY20125N20125	Montgomery County, KS	Montgomery County	56700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Montgomery County	Kansas	0
KS	2012799999	20	127	NCNTY20127N20127	Morris County, KS	Morris County	67100	14150	16150	18150	20150	21800	23400	25000	26600	9999	Morris County	Kansas	0
KS	2012999999	20	129	NCNTY20129N20129	Morton County, KS	Morton County	60800	13600	15550	17500	19400	21000	22550	24100	25650	9999	Morton County	Kansas	0
KS	2013199999	20	131	NCNTY20131N20131	Nemaha County, KS	Nemaha County	77300	16250	18600	20900	23200	25100	26950	28800	30650	9999	Nemaha County	Kansas	0
KS	2013399999	20	133	NCNTY20133N20133	Neosho County, KS	Neosho County	59600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Neosho County	Kansas	0
KS	2013599999	20	135	NCNTY20135N20135	Ness County, KS	Ness County	62600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Ness County	Kansas	0
KS	2013799999	20	137	NCNTY20137N20137	Norton County, KS	Norton County	67400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Norton County	Kansas	0
KS	2013999999	20	139	METRO45820M45820	Topeka, KS MSA	Osage County	77700	16350	18650	21000	23300	25200	27050	28900	30800	9999	Osage County	Kansas	1
KS	2014199999	20	141	NCNTY20141N20141	Osborne County, KS	Osborne County	61400	13600	15550	17500	19400	21000	22550	24100	25650	9999	Osborne County	Kansas	0
KS	2014399999	20	143	NCNTY20143N20143	Ottawa County, KS	Ottawa County	71100	14950	17100	19250	21350	23100	24800	26500	28200	9999	Ottawa County	Kansas	0
KS	2014599999	20	145	NCNTY20145N20145	Pawnee County, KS	Pawnee County	60100	13600	15550	17500	19400	21000	22550	24100	25650	9999	Pawnee County	Kansas	0
KS	2014799999	20	147	NCNTY20147N20147	Phillips County, KS	Phillips County	64600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Phillips County	Kansas	0
KS	2014999999	20	149	METRO31740M31740	Manhattan, KS MSA	Pottawatomie County	69700	15900	18150	20400	22650	24500	26300	28100	29900	9999	Pottawatomie County	Kansas	1
KS	2015199999	20	151	NCNTY20151N20151	Pratt County, KS	Pratt County	70500	14850	16950	19050	21150	22850	24550	26250	27950	9999	Pratt County	Kansas	0
KS	2015399999	20	153	NCNTY20153N20153	Rawlins County, KS	Rawlins County	67200	14150	16150	18150	20150	21800	23400	25000	26600	9999	Rawlins County	Kansas	0
KS	2015599999	20	155	NCNTY20155N20155	Reno County, KS	Reno County	62600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Reno County	Kansas	0
KS	2015799999	20	157	NCNTY20157N20157	Republic County, KS	Republic County	64900	13650	15600	17550	19450	21050	22600	24150	25700	9999	Republic County	Kansas	0
KS	2015999999	20	159	NCNTY20159N20159	Rice County, KS	Rice County	65600	13800	15800	17750	19700	21300	22900	24450	26050	9999	Rice County	Kansas	0
KS	2016199999	20	161	METRO31740M31740	Manhattan, KS MSA	Riley County	69700	15900	18150	20400	22650	24500	26300	28100	29900	9999	Riley County	Kansas	1
KS	2016399999	20	163	NCNTY20163N20163	Rooks County, KS	Rooks County	63500	13600	15550	17500	19400	21000	22550	24100	25650	9999	Rooks County	Kansas	0
KS	2016599999	20	165	NCNTY20165N20165	Rush County, KS	Rush County	68500	14400	16450	18500	20550	22200	23850	25500	27150	9999	Rush County	Kansas	0
KS	2016799999	20	167	NCNTY20167N20167	Russell County, KS	Russell County	64300	13600	15550	17500	19400	21000	22550	24100	25650	9999	Russell County	Kansas	0
KS	2016999999	20	169	NCNTY20169N20169	Saline County, KS	Saline County	70200	14750	16850	18950	21050	22750	24450	26150	27800	9999	Saline County	Kansas	0
KS	2017199999	20	171	NCNTY20171N20171	Scott County, KS	Scott County	71800	14900	17000	19150	21250	22950	24650	26350	28050	9999	Scott County	Kansas	0
KS	2017399999	20	173	METRO48620M48620	Wichita, KS HUD Metro FMR Area	Sedgwick County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9040	Sedgwick County	Kansas	1
KS	2017599999	20	175	NCNTY20175N20175	Seward County, KS	Seward County	52900	13600	15550	17500	19400	21000	22550	24100	25650	9999	Seward County	Kansas	0
KS	2017799999	20	177	METRO45820M45820	Topeka, KS MSA	Shawnee County	77700	16350	18650	21000	23300	25200	27050	28900	30800	8440	Shawnee County	Kansas	1
KS	2017999999	20	179	NCNTY20179N20179	Sheridan County, KS	Sheridan County	76000	15400	17600	19800	21950	23750	25500	27250	29000	9999	Sheridan County	Kansas	0
KS	2018199999	20	181	NCNTY20181N20181	Sherman County, KS	Sherman County	59400	13600	15550	17500	19400	21000	22550	24100	25650	9999	Sherman County	Kansas	0
KS	2018399999	20	183	NCNTY20183N20183	Smith County, KS	Smith County	60600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Smith County	Kansas	0
KS	2018599999	20	185	NCNTY20185N20185	Stafford County, KS	Stafford County	64700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Stafford County	Kansas	0
KS	2018799999	20	187	NCNTY20187N20187	Stanton County, KS	Stanton County	60600	13600	15550	17500	19400	21000	22550	24100	25650	9999	Stanton County	Kansas	0
KS	2018999999	20	189	NCNTY20189N20189	Stevens County, KS	Stevens County	69600	14600	16700	18800	20850	22550	24200	25900	27550	9999	Stevens County	Kansas	0
KS	2019199999	20	191	METRO48620N20191	Sumner County, KS HUD Metro FMR Area	Sumner County	71900	15100	17250	19400	21550	23300	25000	26750	28450	9999	Sumner County	Kansas	1
KS	2019399999	20	193	NCNTY20193N20193	Thomas County, KS	Thomas County	70600	14850	17000	19100	21200	22900	24600	26300	28000	9999	Thomas County	Kansas	0
KS	2019599999	20	195	NCNTY20195N20195	Trego County, KS	Trego County	73800	15550	17750	19950	22150	23950	25700	27500	29250	9999	Trego County	Kansas	0
KS	2019799999	20	197	METRO45820M45820	Topeka, KS MSA	Wabaunsee County	77700	16350	18650	21000	23300	25200	27050	28900	30800	9999	Wabaunsee County	Kansas	1
KS	2019999999	20	199	NCNTY20199N20199	Wallace County, KS	Wallace County	87800	18000	20600	23150	25700	27800	29850	31900	33950	9999	Wallace County	Kansas	0
KS	2020199999	20	201	NCNTY20201N20201	Washington County, KS	Washington County	62800	13600	15550	17500	19400	21000	22550	24100	25650	9999	Washington County	Kansas	0
KS	2020399999	20	203	NCNTY20203N20203	Wichita County, KS	Wichita County	68100	14350	16400	18450	20450	22100	23750	25400	27000	9999	Wichita County	Kansas	0
KS	2020599999	20	205	NCNTY20205N20205	Wilson County, KS	Wilson County	59300	13600	15550	17500	19400	21000	22550	24100	25650	9999	Wilson County	Kansas	0
KS	2020799999	20	207	NCNTY20207N20207	Woodson County, KS	Woodson County	56000	13600	15550	17500	19400	21000	22550	24100	25650	9999	Woodson County	Kansas	0
KS	2020999999	20	209	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Wyandotte County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Wyandotte County	Kansas	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
KY	2100199999	21	1	NCNTY21001N21001	Adair County, KY	Adair County	47700	11200	12800	14400	16000	17300	18600	19850	21150	9999	Adair County	Kentucky	0
KY	2100399999	21	3	METRO14540N21003	Allen County, KY HUD Metro FMR Area	Allen County	54500	11450	13100	14750	16350	17700	19000	20300	21600	9999	Allen County	Kentucky	1
KY	2100599999	21	5	NCNTY21005N21005	Anderson County, KY	Anderson County	69700	14650	16750	18850	20900	22600	24250	25950	27600	9999	Anderson County	Kentucky	0
KY	2100799999	21	7	NCNTY21007N21007	Ballard County, KY	Ballard County	58200	12250	14000	15750	17450	18850	20250	21650	23050	9999	Ballard County	Kentucky	0
KY	2100999999	21	9	NCNTY21009N21009	Barren County, KY	Barren County	50100	11200	12800	14400	16000	17300	18600	19850	21150	9999	Barren County	Kentucky	0
KY	2101199999	21	11	NCNTY21011N21011	Bath County, KY	Bath County	45000	11200	12800	14400	16000	17300	18600	19850	21150	9999	Bath County	Kentucky	0
KY	2101399999	21	13	NCNTY21013N21013	Bell County, KY	Bell County	33100	11200	12800	14400	16000	17300	18600	19850	21150	9999	Bell County	Kentucky	0
KY	2101599999	21	15	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Boone County	86300	18150	20750	23350	25900	28000	30050	32150	34200	1640	Boone County	Kentucky	1
KY	2101799999	21	17	METRO30460M30460	Lexington-Fayette, KY MSA	Bourbon County	79400	16700	19050	21450	23800	25750	27650	29550	31450	4280	Bourbon County	Kentucky	1
KY	2101999999	21	19	METRO26580M26580	Huntington-Ashland, WV-KY-OH HUD Metro FMR Area	Boyd County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3400	Boyd County	Kentucky	1
KY	2102199999	21	21	NCNTY21021N21021	Boyle County, KY	Boyle County	58600	12350	14100	15850	17600	19050	20450	21850	23250	9999	Boyle County	Kentucky	0
KY	2102399999	21	23	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Bracken County	86300	18150	20750	23350	25900	28000	30050	32150	34200	9999	Bracken County	Kentucky	1
KY	2102599999	21	25	NCNTY21025N21025	Breathitt County, KY	Breathitt County	33700	11200	12800	14400	16000	17300	18600	19850	21150	9999	Breathitt County	Kentucky	0
KY	2102799999	21	27	NCNTY21027N21027	Breckinridge County, KY	Breckinridge County	62300	13100	15000	16850	18700	20200	21700	23200	24700	9999	Breckinridge County	Kentucky	0
KY	2102999999	21	29	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Bullitt County	77500	16300	18600	20950	23250	25150	27000	28850	30700	4520	Bullitt County	Kentucky	1
KY	2103199999	21	31	METRO14540N21031	Butler County, KY HUD Metro FMR Area	Butler County	54600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Butler County	Kentucky	1
KY	2103399999	21	33	NCNTY21033N21033	Caldwell County, KY	Caldwell County	58200	12250	14000	15750	17450	18850	20250	21650	23050	9999	Caldwell County	Kentucky	0
KY	2103599999	21	35	NCNTY21035N21035	Calloway County, KY	Calloway County	60100	12650	14450	16250	18050	19500	20950	22400	23850	9999	Calloway County	Kentucky	0
KY	2103799999	21	37	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Campbell County	86300	18150	20750	23350	25900	28000	30050	32150	34200	1640	Campbell County	Kentucky	1
KY	2103999999	21	39	NCNTY21039N21039	Carlisle County, KY	Carlisle County	55200	11600	13250	14900	16550	17900	19200	20550	21850	9999	Carlisle County	Kentucky	0
KY	2104199999	21	41	NCNTY21041N21041	Carroll County, KY	Carroll County	51400	11200	12800	14400	16000	17300	18600	19850	21150	9999	Carroll County	Kentucky	0
KY	2104399999	21	43	NCNTY21043N21043	Carter County, KY	Carter County	45400	11200	12800	14400	16000	17300	18600	19850	21150	3400	Carter County	Kentucky	0
KY	2104599999	21	45	NCNTY21045N21045	Casey County, KY	Casey County	45400	11200	12800	14400	16000	17300	18600	19850	21150	9999	Casey County	Kentucky	0
KY	2104799999	21	47	METRO17300M17300	Clarksville, TN-KY MSA	Christian County	68900	13800	15800	17750	19700	21300	22900	24450	26050	1660	Christian County	Kentucky	1
KY	2104999999	21	49	METRO30460M30460	Lexington-Fayette, KY MSA	Clark County	79400	16700	19050	21450	23800	25750	27650	29550	31450	4280	Clark County	Kentucky	1
KY	2105199999	21	51	NCNTY21051N21051	Clay County, KY	Clay County	34000	11200	12800	14400	16000	17300	18600	19850	21150	9999	Clay County	Kentucky	0
KY	2105399999	21	53	NCNTY21053N21053	Clinton County, KY	Clinton County	39600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Clinton County	Kentucky	0
KY	2105599999	21	55	NCNTY21055N21055	Crittenden County, KY	Crittenden County	58900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Crittenden County	Kentucky	0
KY	2105799999	21	57	NCNTY21057N21057	Cumberland County, KY	Cumberland County	45700	11200	12800	14400	16000	17300	18600	19850	21150	9999	Cumberland County	Kentucky	0
KY	2105999999	21	59	METRO36980M36980	Owensboro, KY MSA	Daviess County	63400	13700	15650	17600	19550	21150	22700	24250	25850	5990	Daviess County	Kentucky	1
KY	2106199999	21	61	METRO14540M14540	Bowling Green, KY HUD Metro FMR Area	Edmonson County	64400	13150	15000	16900	18750	20250	21750	23250	24750	9999	Edmonson County	Kentucky	1
KY	2106399999	21	63	NCNTY21063N21063	Elliott County, KY	Elliott County	34900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Elliott County	Kentucky	0
KY	2106599999	21	65	NCNTY21065N21065	Estill County, KY	Estill County	42300	11200	12800	14400	16000	17300	18600	19850	21150	9999	Estill County	Kentucky	0
KY	2106799999	21	67	METRO30460M30460	Lexington-Fayette, KY MSA	Fayette County	79400	16700	19050	21450	23800	25750	27650	29550	31450	4280	Fayette County	Kentucky	1
KY	2106999999	21	69	NCNTY21069N21069	Fleming County, KY	Fleming County	53600	11300	12900	14500	16100	17400	18700	20000	21300	9999	Fleming County	Kentucky	0
KY	2107199999	21	71	NCNTY21071N21071	Floyd County, KY	Floyd County	40200	11200	12800	14400	16000	17300	18600	19850	21150	9999	Floyd County	Kentucky	0
KY	2107399999	21	73	NCNTY21073N21073	Franklin County, KY	Franklin County	71100	14950	17100	19250	21350	23100	24800	26500	28200	9999	Franklin County	Kentucky	0
KY	2107599999	21	75	NCNTY21075N21075	Fulton County, KY	Fulton County	43100	11200	12800	14400	16000	17300	18600	19850	21150	9999	Fulton County	Kentucky	0
KY	2107799999	21	77	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Gallatin County	86300	18150	20750	23350	25900	28000	30050	32150	34200	2910	Gallatin County	Kentucky	1
KY	2107999999	21	79	NCNTY21079N21079	Garrard County, KY	Garrard County	62900	13200	15100	17000	18850	20400	21900	23400	24900	9999	Garrard County	Kentucky	0
KY	2108199999	21	81	METRO17140MM3020	Grant County, KY HUD Metro FMR Area	Grant County	52900	11200	12800	14400	16000	17300	18600	19850	21150	3020	Grant County	Kentucky	1
KY	2108399999	21	83	NCNTY21083N21083	Graves County, KY	Graves County	56200	11800	13500	15200	16850	18200	19550	20900	22250	9999	Graves County	Kentucky	0
KY	2108599999	21	85	NCNTY21085N21085	Grayson County, KY	Grayson County	46500	11200	12800	14400	16000	17300	18600	19850	21150	9999	Grayson County	Kentucky	0
KY	2108799999	21	87	NCNTY21087N21087	Green County, KY	Green County	51800	11200	12800	14400	16000	17300	18600	19850	21150	9999	Green County	Kentucky	0
KY	2108999999	21	89	METRO26580M26580	Huntington-Ashland, WV-KY-OH HUD Metro FMR Area	Greenup County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3400	Greenup County	Kentucky	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
KY	2109199999	21	91	METRO36980M36980	Owensboro, KY MSA	Hancock County	63400	13700	15650	17600	19550	21150	22700	24250	25850	9999	Hancock County	Kentucky	1
KY	2109399999	21	93	METRO21060M21060	Elizabethtown, KY HUD Metro FMR Area	Hardin County	68600	14450	16500	18550	20600	22250	23900	25550	27200	9999	Hardin County	Kentucky	1
KY	2109599999	21	95	NCNTY21095N21095	Harlan County, KY	Harlan County	34400	11200	12800	14400	16000	17300	18600	19850	21150	9999	Harlan County	Kentucky	0
KY	2109799999	21	97	NCNTY21097N21097	Harrison County, KY	Harrison County	61800	12750	14600	16400	18200	19700	21150	22600	24050	9999	Harrison County	Kentucky	0
KY	2109999999	21	99	NCNTY21099N21099	Hart County, KY	Hart County	48300	11200	12800	14400	16000	17300	18600	19850	21150	9999	Hart County	Kentucky	0
KY	2110199999	21	101	METRO21780M21780	Evansville, IN-KY MSA	Henderson County	74800	15250	17400	19600	21750	23500	25250	27000	28750	2440	Henderson County	Kentucky	1
KY	2110399999	21	103	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Henry County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Henry County	Kentucky	1
KY	2110599999	21	105	NCNTY21105N21105	Hickman County, KY	Hickman County	51900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Hickman County	Kentucky	0
KY	2110799999	21	107	NCNTY21107N21107	Hopkins County, KY	Hopkins County	60100	12650	14450	16250	18050	19500	20950	22400	23850	9999	Hopkins County	Kentucky	0
KY	2110999999	21	109	NCNTY21109N21109	Jackson County, KY	Jackson County	40700	11200	12800	14400	16000	17300	18600	19850	21150	9999	Jackson County	Kentucky	0
KY	2111199999	21	111	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Jefferson County	77500	16300	18600	20950	23250	25150	27000	28850	30700	4520	Jefferson County	Kentucky	1
KY	2111399999	21	113	METRO30460M30460	Lexington-Fayette, KY MSA	Jessamine County	79400	16700	19050	21450	23800	25750	27650	29550	31450	4280	Jessamine County	Kentucky	1
KY	2111599999	21	115	NCNTY21115N21115	Johnson County, KY	Johnson County	49800	11200	12800	14400	16000	17300	18600	19850	21150	9999	Johnson County	Kentucky	0
KY	2111799999	21	117	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Kenton County	86300	18150	20750	23350	25900	28000	30050	32150	34200	1640	Kenton County	Kentucky	1
KY	2111999999	21	119	NCNTY21119N21119	Knott County, KY	Knott County	40900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Knott County	Kentucky	0
KY	2112199999	21	121	NCNTY21121N21121	Knox County, KY	Knox County	34800	11200	12800	14400	16000	17300	18600	19850	21150	9999	Knox County	Kentucky	0
KY	2112399999	21	123	METRO21060M21060	Elizabethtown, KY HUD Metro FMR Area	Larue County	68600	14450	16500	18550	20600	22250	23900	25550	27200	9999	Larue County	Kentucky	1
KY	2112599999	21	125	NCNTY21125N21125	Laurel County, KY	Laurel County	48700	11200	12800	14400	16000	17300	18600	19850	21150	9999	Laurel County	Kentucky	0
KY	2112799999	21	127	NCNTY21127N21127	Lawrence County, KY	Lawrence County	44200	11200	12800	14400	16000	17300	18600	19850	21150	9999	Lawrence County	Kentucky	0
KY	2112999999	21	129	NCNTY21129N21129	Lee County, KY	Lee County	37200	11200	12800	14400	16000	17300	18600	19850	21150	9999	Lee County	Kentucky	0
KY	2113199999	21	131	NCNTY21131N21131	Leslie County, KY	Leslie County	39600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Leslie County	Kentucky	0
KY	2113399999	21	133	NCNTY21133N21133	Letcher County, KY	Letcher County	39900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Letcher County	Kentucky	0
KY	2113599999	21	135	NCNTY21135N21135	Lewis County, KY	Lewis County	48200	11200	12800	14400	16000	17300	18600	19850	21150	9999	Lewis County	Kentucky	0
KY	2113799999	21	137	NCNTY21137N21137	Lincoln County, KY	Lincoln County	49200	11200	12800	14400	16000	17300	18600	19850	21150	9999	Lincoln County	Kentucky	0
KY	2113999999	21	139	NCNTY21139N21139	Livingston County, KY	Livingston County	58500	12300	14050	15800	17550	19000	20400	21800	23200	9999	Livingston County	Kentucky	0
KY	2114199999	21	141	NCNTY21141N21141	Logan County, KY	Logan County	57600	12150	13850	15600	17300	18700	20100	21500	22850	9999	Logan County	Kentucky	0
KY	2114399999	21	143	NCNTY21143N21143	Lyon County, KY	Lyon County	64900	13650	15600	17550	19450	21050	22600	24150	25700	9999	Lyon County	Kentucky	0
KY	2114599999	21	145	NCNTY21145N21145	McCracken County, KY	McCracken County	80000	13250	15150	17050	18900	20450	21950	23450	24950	9999	McCracken County	Kentucky	0
KY	2114799999	21	147	NCNTY21147N21147	McCreary County, KY	McCreary County	27000	11200	12800	14400	16000	17300	18600	19850	21150	9999	McCreary County	Kentucky	0
KY	2114999999	21	149	METRO36980M36980	Owensboro, KY MSA	McLean County	63400	13700	15650	17600	19550	21150	22700	24250	25850	9999	McLean County	Kentucky	1
KY	2115199999	21	151	NCNTY21151N21151	Madison County, KY	Madison County	70600	14250	16250	18300	20300	21950	23550	25200	26800	4280	Madison County	Kentucky	0
KY	2115399999	21	153	NCNTY21153N21153	Magoffin County, KY	Magoffin County	40600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Magoffin County	Kentucky	0
KY	2115599999	21	155	NCNTY21155N21155	Marion County, KY	Marion County	56800	11600	13250	14900	16550	17900	19200	20550	21850	9999	Marion County	Kentucky	0
KY	2115799999	21	157	NCNTY21157N21157	Marshall County, KY	Marshall County	67100	13900	15900	17900	19850	21450	23050	24650	26250	9999	Marshall County	Kentucky	0
KY	2115999999	21	159	NCNTY21159N21159	Martin County, KY	Martin County	43100	11200	12800	14400	16000	17300	18600	19850	21150	9999	Martin County	Kentucky	0
KY	2116199999	21	161	NCNTY21161N21161	Mason County, KY	Mason County	61200	12150	13850	15600	17300	18700	20100	21500	22850	9999	Mason County	Kentucky	0
KY	2116399999	21	163	METRO21060N21163	Meade County, KY HUD Metro FMR Area	Meade County	66300	13900	15850	17850	19800	21400	23000	24600	26150	9999	Meade County	Kentucky	1
KY	2116599999	21	165	NCNTY21165N21165	Menifee County, KY	Menifee County	49900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Menifee County	Kentucky	0
KY	2116799999	21	167	NCNTY21167N21167	Mercer County, KY	Mercer County	66000	13900	15850	17850	19800	21400	23000	24600	26150	9999	Mercer County	Kentucky	0
KY	2116999999	21	169	NCNTY21169N21169	Metcalfe County, KY	Metcalfe County	44900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Metcalfe County	Kentucky	0
KY	2117199999	21	171	NCNTY21171N21171	Monroe County, KY	Monroe County	52100	11200	12800	14400	16000	17300	18600	19850	21150	9999	Monroe County	Kentucky	0
KY	2117399999	21	173	NCNTY21173N21173	Montgomery County, KY	Montgomery County	56400	11700	13350	15000	16650	18000	19350	20650	22000	9999	Montgomery County	Kentucky	0
KY	2117599999	21	175	NCNTY21175N21175	Morgan County, KY	Morgan County	43900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Morgan County	Kentucky	0
KY	2117799999	21	177	NCNTY21177N21177	Muhlenberg County, KY	Muhlenberg County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Muhlenberg County	Kentucky	0
KY	2117999999	21	179	NCNTY21179N21179	Nelson County, KY	Nelson County	71200	14950	17100	19250	21350	23100	24800	26500	28200	9999	Nelson County	Kentucky	0
KY	2118199999	21	181	NCNTY21181N21181	Nicholas County, KY	Nicholas County	54500	11450	13100	14750	16350	17700	19000	20300	21600	9999	Nicholas County	Kentucky	0
KY	2118399999	21	183	NCNTY21183N21183	Ohio County, KY	Ohio County	50600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Ohio County	Kentucky	0
KY	2118599999	21	185	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Oldham County	77500	16300	18600	20950	23250	25150	27000	28850	30700	4520	Oldham County	Kentucky	1
KY	2118799999	21	187	NCNTY21187N21187	Owen County, KY	Owen County	54700	11500	13150	14800	16400	17750	19050	20350	21650	9999	Owen County	Kentucky	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
KY	2118999999	21	189	NCNTY21189N21189	Owsley County, KY	Owsley County	41300	11200	12800	14400	16000	17300	18600	19850	21150	9999	Owsley County	Kentucky	0
KY	2119199999	21	191	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Pendleton County	86300	18150	20750	23350	25900	28000	30050	32150	34200	6070	Pendleton County	Kentucky	1
KY	2119399999	21	193	NCNTY21193N21193	Perry County, KY	Perry County	45700	11200	12800	14400	16000	17300	18600	19850	21150	9999	Perry County	Kentucky	0
KY	2119599999	21	195	NCNTY21195N21195	Pike County, KY	Pike County	43600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Pike County	Kentucky	0
KY	2119799999	21	197	NCNTY21197N21197	Powell County, KY	Powell County	52600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Powell County	Kentucky	0
KY	2119999999	21	199	NCNTY21199N21199	Pulaski County, KY	Pulaski County	50700	11200	12800	14400	16000	17300	18600	19850	21150	9999	Pulaski County	Kentucky	0
KY	2120199999	21	201	NCNTY21201N21201	Robertson County, KY	Robertson County	54800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Robertson County	Kentucky	0
KY	2120399999	21	203	NCNTY21203N21203	Rockcastle County, KY	Rockcastle County	50900	11200	12800	14400	16000	17300	18600	19850	21150	9999	Rockcastle County	Kentucky	0
KY	2120599999	21	205	NCNTY21205N21205	Rowan County, KY	Rowan County	54200	11400	13000	14650	16250	17550	18850	20150	21450	9999	Rowan County	Kentucky	0
KY	2120799999	21	207	NCNTY21207N21207	Russell County, KY	Russell County	46000	11200	12800	14400	16000	17300	18600	19850	21150	9999	Russell County	Kentucky	0
KY	2120999999	21	209	METRO30460M30460	Lexington-Fayette, KY MSA	Scott County	79400	16700	19050	21450	23800	25750	27650	29550	31450	4280	Scott County	Kentucky	1
KY	2121199999	21	211	METRO31140N21211	Shelby County, KY HUD Metro FMR Area	Shelby County	78900	16600	18950	21300	23650	25550	27450	29350	31250	9999	Shelby County	Kentucky	1
KY	2121399999	21	213	NCNTY21213N21213	Simpson County, KY	Simpson County	59300	12500	14250	16050	17800	19250	20650	22100	23500	9999	Simpson County	Kentucky	0
KY	2121599999	21	215	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Spencer County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Spencer County	Kentucky	1
KY	2121799999	21	217	NCNTY21217N21217	Taylor County, KY	Taylor County	48600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Taylor County	Kentucky	0
KY	2121999999	21	219	NCNTY21219N21219	Todd County, KY	Todd County	51100	11200	12800	14400	16000	17300	18600	19850	21150	9999	Todd County	Kentucky	0
KY	2122199999	21	221	METRO17300M17300	Clarksville, TN-KY MSA	Trigg County	68900	13800	15800	17750	19700	21300	22900	24450	26050	9999	Trigg County	Kentucky	1
KY	2122399999	21	223	METRO31140M31140	Louisville, KY-IN HUD Metro FMR Area	Trimble County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Trimble County	Kentucky	1
KY	2122599999	21	225	NCNTY21225N21225	Union County, KY	Union County	56300	11850	13550	15250	16900	18300	19650	21000	22350	9999	Union County	Kentucky	0
KY	2122799999	21	227	METRO14540M14540	Bowling Green, KY HUD Metro FMR Area	Warren County	64400	13150	15000	16900	18750	20250	21750	23250	24750	9999	Warren County	Kentucky	1
KY	2122999999	21	229	NCNTY21229N21229	Washington County, KY	Washington County	61500	12800	14600	16450	18250	19750	21200	22650	24100	9999	Washington County	Kentucky	0
KY	2123199999	21	231	NCNTY21231N21231	Wayne County, KY	Wayne County	45000	11200	12800	14400	16000	17300	18600	19850	21150	9999	Wayne County	Kentucky	0
KY	2123399999	21	233	NCNTY21233N21233	Webster County, KY	Webster County	52600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Webster County	Kentucky	0
KY	2123599999	21	235	NCNTY21235N21235	Whitley County, KY	Whitley County	46600	11200	12800	14400	16000	17300	18600	19850	21150	9999	Whitley County	Kentucky	0
KY	2123799999	21	237	NCNTY21237N21237	Wolfe County, KY	Wolfe County	35200	11200	12800	14400	16000	17300	18600	19850	21150	9999	Wolfe County	Kentucky	0
KY	2123999999	21	239	METRO30460M30460	Lexington-Fayette, KY MSA	Woodford County	79400	16700	19050	21450	23800	25750	27650	29550	31450	4280	Woodford County	Kentucky	1
LA	2200199999	22	1	METRO29180N22001	Acadia Parish, LA HUD Metro FMR Area	Acadia Parish	55300	11600	13250	14900	16550	17900	19200	20550	21850	3880	Acadia Parish	Louisiana	1
LA	2200399999	22	3	NCNTY22003N22003	Allen Parish, LA	Allen Parish	58200	12250	14000	15750	17450	18850	20250	21650	23050	9999	Allen Parish	Louisiana	0
LA	2200599999	22	5	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	Ascension Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	760	Ascension Parish	Louisiana	1
LA	2200799999	22	7	NCNTY22007N22007	Assumption Parish, LA	Assumption Parish	64700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Assumption Parish	Louisiana	0
LA	2200999999	22	9	NCNTY22009N22009	Avoyelles Parish, LA	Avoyelles Parish	52500	11050	12600	14200	15750	17050	18300	19550	20800	9999	Avoyelles Parish	Louisiana	0
LA	2201199999	22	11	NCNTY22011N22011	Beauregard Parish, LA	Beauregard Parish	65700	13800	15800	17750	19700	21300	22900	24450	26050	9999	Beauregard Parish	Louisiana	0
LA	2201399999	22	13	NCNTY22013N22013	Bienville Parish, LA	Bienville Parish	47700	10550	12050	13550	15050	16300	17500	18700	19900	9999	Bienville Parish	Louisiana	0
LA	2201599999	22	15	METRO43340M43340	Shreveport-Bossier City, LA HUD Metro FMR Area	Bossier Parish	56700	11900	13600	15300	17000	18400	19750	21100	22450	7680	Bossier Parish	Louisiana	1
LA	2201799999	22	17	METRO43340M43340	Shreveport-Bossier City, LA HUD Metro FMR Area	Caddo Parish	56700	11900	13600	15300	17000	18400	19750	21100	22450	7680	Caddo Parish	Louisiana	1
LA	2201999999	22	19	METRO29340M29340	Lake Charles, LA MSA	Calcasieu Parish	70800	12950	14800	16650	18500	20000	21500	22950	24450	3960	Calcasieu Parish	Louisiana	1
LA	2202199999	22	21	NCNTY22021N22021	Caldwell Parish, LA	Caldwell Parish	49000	10550	12050	13550	15050	16300	17500	18700	19900	9999	Caldwell Parish	Louisiana	0
LA	2202399999	22	23	METRO29340M29340	Lake Charles, LA MSA	Cameron Parish	70800	12950	14800	16650	18500	20000	21500	22950	24450	9999	Cameron Parish	Louisiana	1
LA	2202599999	22	25	NCNTY22025N22025	Catahoula Parish, LA	Catahoula Parish	58100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Catahoula Parish	Louisiana	0
LA	2202799999	22	27	NCNTY22027N22027	Claiborne Parish, LA	Claiborne Parish	40200	10550	12050	13550	15050	16300	17500	18700	19900	9999	Claiborne Parish	Louisiana	0
LA	2202999999	22	29	NCNTY22029N22029	Concordia Parish, LA	Concordia Parish	44500	10550	12050	13550	15050	16300	17500	18700	19900	9999	Concordia Parish	Louisiana	0
LA	2203199999	22	31	METRO43340M43340	Shreveport-Bossier City, LA HUD Metro FMR Area	De Soto Parish	56700	11900	13600	15300	17000	18400	19750	21100	22450	9999	De Soto Parish	Louisiana	1
LA	2203399999	22	33	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	East Baton Rouge Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	760	East Baton Rouge Parish	Louisiana	1
LA	2203599999	22	35	NCNTY22035N22035	East Carroll Parish, LA	East Carroll Parish	29700	10550	12050	13550	15050	16300	17500	18700	19900	9999	East Carroll Parish	Louisiana	0
LA	2203799999	22	37	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	East Feliciana Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	East Feliciana Parish	Louisiana	1
LA	2203999999	22	39	NCNTY22039N22039	Evangeline Parish, LA	Evangeline Parish	44000	10550	12050	13550	15050	16300	17500	18700	19900	9999	Evangeline Parish	Louisiana	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
LA	2204199999	22	41	NCNTY22041N22041	Franklin Parish, LA	Franklin Parish	50100	10550	12050	13550	15050	16300	17500	18700	19900	9999	Franklin Parish	Louisiana	0
LA	2204399999	22	43	METRO10780M10780	Alexandria, LA MSA	Grant Parish	58400	12250	14000	15750	17500	18900	20300	21700	23100	9999	Grant Parish	Louisiana	1
LA	2204599999	22	45	METRO29180N22045	Iberia Parish, LA HUD Metro FMR Area	Iberia Parish	54800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Iberia Parish	Louisiana	1
LA	2204799999	22	47	METRO12940N22047	Iberville Parish, LA HUD Metro FMR Area	Iberville Parish	59300	12500	14250	16050	17800	19250	20650	22100	23500	9999	Iberville Parish	Louisiana	1
LA	2204999999	22	49	NCNTY22049N22049	Jackson Parish, LA	Jackson Parish	50900	10700	12200	13750	15250	16500	17700	18950	20150	9999	Jackson Parish	Louisiana	0
LA	2205199999	22	51	METRO35380M35380	New Orleans-Metairie, LA HUD Metro FMR Area	Jefferson Parish	70400	14800	16900	19000	21100	22800	24500	26200	27900	5560	Jefferson Parish	Louisiana	1
LA	2205399999	22	53	NCNTY22053N22053	Jefferson Davis Parish, LA	Jefferson Davis Parish	57400	12050	13800	15500	17200	18600	20000	21350	22750	9999	Jefferson Davis Parish	Louisiana	0
LA	2205599999	22	55	METRO29180M29180	Lafayette, LA HUD Metro FMR Area	Lafayette Parish	65200	13700	15650	17600	19550	21150	22700	24250	25850	3880	Lafayette Parish	Louisiana	1
LA	2205799999	22	57	METRO26380M26380	Houma-Thibodaux, LA MSA	Lafourche Parish	67200	13800	15800	17750	19700	21300	22900	24450	26050	3350	Lafourche Parish	Louisiana	1
LA	2205999999	22	59	NCNTY22059N22059	La Salle Parish, LA	La Salle Parish	44200	10550	12050	13550	15050	16300	17500	18700	19900	9999	La Salle Parish	Louisiana	0
LA	2206199999	22	61	NCNTY22061N22061	Lincoln Parish, LA	Lincoln Parish	58000	12200	13950	15700	17400	18800	20200	21600	23000	9999	Lincoln Parish	Louisiana	0
LA	2206399999	22	63	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	Livingston Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	760	Livingston Parish	Louisiana	1
LA	2206599999	22	65	NCNTY22065N22065	Madison Parish, LA	Madison Parish	38300	10550	12050	13550	15050	16300	17500	18700	19900	9999	Madison Parish	Louisiana	0
LA	2206799999	22	67	NCNTY22067N22067	Morehouse Parish, LA	Morehouse Parish	43900	10550	12050	13550	15050	16300	17500	18700	19900	9999	Morehouse Parish	Louisiana	0
LA	2206999999	22	69	NCNTY22069N22069	Natchitoches Parish, LA	Natchitoches Parish	49600	10550	12050	13550	15050	16300	17500	18700	19900	9999	Natchitoches Parish	Louisiana	0
LA	2207199999	22	71	METRO35380M35380	New Orleans-Metairie, LA HUD Metro FMR Area	Orleans Parish	70400	14800	16900	19000	21100	22800	24500	26200	27900	5560	Orleans Parish	Louisiana	1
LA	2207399999	22	73	METRO33740M33740	Monroe, LA MSA	Ouachita Parish	56700	11600	13250	14900	16550	17900	19200	20550	21850	5200	Ouachita Parish	Louisiana	1
LA	2207599999	22	75	METRO35380M35380	New Orleans-Metairie, LA HUD Metro FMR Area	Plaquemines Parish	70400	14800	16900	19000	21100	22800	24500	26200	27900	5560	Plaquemines Parish	Louisiana	1
LA	2207799999	22	77	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	Pointe Coupee Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Pointe Coupee Parish	Louisiana	1
LA	2207999999	22	79	METRO10780M10780	Alexandria, LA MSA	Rapides Parish	58400	12250	14000	15750	17500	18900	20300	21700	23100	220	Rapides Parish	Louisiana	1
LA	2208199999	22	81	NCNTY22081N22081	Red River Parish, LA	Red River Parish	53400	11200	12800	14400	16000	17300	18600	19850	21150	9999	Red River Parish	Louisiana	0
LA	2208399999	22	83	NCNTY22083N22083	Richland Parish, LA	Richland Parish	49300	10550	12050	13550	15050	16300	17500	18700	19900	9999	Richland Parish	Louisiana	0
LA	2208599999	22	85	NCNTY22085N22085	Sabine Parish, LA	Sabine Parish	57300	12050	13800	15500	17200	18600	20000	21350	22750	9999	Sabine Parish	Louisiana	0
LA	2208799999	22	87	METRO35380M35380	New Orleans-Metairie, LA HUD Metro FMR Area	St. Bernard Parish	70400	14800	16900	19000	21100	22800	24500	26200	27900	5560	St. Bernard Parish	Louisiana	1
LA	2208999999	22	89	METRO35380M35380	New Orleans-Metairie, LA HUD Metro FMR Area	St. Charles Parish	70400	14800	16900	19000	21100	22800	24500	26200	27900	5560	St. Charles Parish	Louisiana	1
LA	2209199999	22	91	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	St. Helena Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	St. Helena Parish	Louisiana	1
LA	2209399999	22	93	METRO35380N22093	St. James Parish, LA HUD Metro FMR Area	St. James Parish	67300	14150	16200	18200	20200	21850	23450	25050	26700	6990	St. James Parish	Louisiana	1
LA	2209599999	22	95	METRO35380M35380	New Orleans-Metairie, LA HUD Metro FMR Area	St. John the Baptist Parish	70400	14800	16900	19000	21100	22800	24500	26200	27900	5560	St. John the Baptist Parish	Louisiana	1
LA	2209799999	22	97	NCNTY22097N22097	St. Landry Parish, LA	St. Landry Parish	43800	10550	12050	13550	15050	16300	17500	18700	19900	3880	St. Landry Parish	Louisiana	0
LA	2209999999	22	99	METRO29180M29180	Lafayette, LA HUD Metro FMR Area	St. Martin Parish	65200	13700	15650	17600	19550	21150	22700	24250	25850	3880	St. Martin Parish	Louisiana	1
LA	2210199999	22	101	NCNTY22101N22101	St. Mary Parish, LA	St. Mary Parish	54200	11400	13000	14650	16250	17550	18850	20150	21450	9999	St. Mary Parish	Louisiana	0
LA	2210399999	22	103	METRO35380M35380	New Orleans-Metairie, LA HUD Metro FMR Area	St. Tammany Parish	70400	14800	16900	19000	21100	22800	24500	26200	27900	5560	St. Tammany Parish	Louisiana	1
LA	2210599999	22	105	METRO25220M25220	Hammond, LA MSA	Tangipahoa Parish	54100	13250	15150	17050	18900	20450	21950	23450	24950	9999	Tangipahoa Parish	Louisiana	1
LA	2210799999	22	107	NCNTY22107N22107	Tensas Parish, LA	Tensas Parish	34100	10550	12050	13550	15050	16300	17500	18700	19900	9999	Tensas Parish	Louisiana	0
LA	2210999999	22	109	METRO26380M26380	Houma-Thibodaux, LA MSA	Terrebonne Parish	67200	13800	15800	17750	19700	21300	22900	24450	26050	3350	Terrebonne Parish	Louisiana	1
LA	2211199999	22	111	METRO33740M33740	Monroe, LA MSA	Union Parish	56700	11600	13250	14900	16550	17900	19200	20550	21850	9999	Union Parish	Louisiana	1
LA	2211399999	22	113	METRO29180N22113	Vermilion Parish, LA HUD Metro FMR Area	Vermilion Parish	62800	13200	15100	17000	18850	20400	21900	23400	24900	9999	Vermilion Parish	Louisiana	1
LA	2211599999	22	115	NCNTY22115N22115	Vernon Parish, LA	Vernon Parish	56800	13100	15000	16850	18700	20200	21700	23200	24700	9999	Vernon Parish	Louisiana	0
LA	2211799999	22	117	NCNTY22117N22117	Washington Parish, LA	Washington Parish	46500	10550	12050	13550	15050	16300	17500	18700	19900	9999	Washington Parish	Louisiana	0
LA	2211999999	22	119	METRO43340N22119	Webster Parish, LA HUD Metro FMR Area	Webster Parish	44000	10550	12050	13550	15050	16300	17500	18700	19900	7680	Webster Parish	Louisiana	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
LA	2212199999	22	121	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	West Baton Rouge Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	760	West Baton Rouge Parish	Louisiana	1
LA	2212399999	22	123	NCNTY22123N22123	West Carroll Parish, LA	West Carroll Parish	52600	11100	12650	14250	15800	17100	18350	19600	20900	9999	West Carroll Parish	Louisiana	0
LA	2212599999	22	125	METRO12940M12940	Baton Rouge, LA HUD Metro FMR Area	West Feliciana Parish	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	West Feliciana Parish	Louisiana	1
LA	2212799999	22	127	NCNTY22127N22127	Winn Parish, LA	Winn Parish	43500	10550	12050	13550	15050	16300	17500	18700	19900	9999	Winn Parish	Louisiana	0
ME	2300102060	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Auburn city	Maine	1
ME	2300119105	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	9999	Durham town	Maine	1
ME	2300129255	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Greene town	Maine	1
ME	2300138565	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	9999	Leeds town	Maine	1
ME	2300138740	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Lewiston city	Maine	1
ME	2300140035	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Lisbon town	Maine	1
ME	2300140665	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	9999	Livermore town	Maine	1
ME	2300140770	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	9999	Livermore Falls town	Maine	1
ME	2300144585	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Mechanic Falls town	Maine	1
ME	2300146160	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	9999	Minot town	Maine	1
ME	2300160020	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Poland town	Maine	1
ME	2300164570	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Sabattus town	Maine	1
ME	2300177800	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Turner town	Maine	1
ME	2300179585	23	1	METRO30340M30340	Lewiston-Auburn, ME MSA	Androscoggin County	75900	14700	16800	18900	20950	22650	24350	26000	27700	4240	Wales town	Maine	1
ME	2300300800	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Allagash town	Maine	0
ME	2300301220	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Amity town	Maine	0
ME	2300301710	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Ashland town	Maine	0
ME	2300302760	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Bancroft town	Maine	0
ME	2300305385	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Blaine town	Maine	0
ME	2300307065	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Bridgewater town	Maine	0
ME	2300310565	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Caribou city	Maine	0
ME	2300311020	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Cary plantation	Maine	0
ME	2300311300	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Castle Hill town	Maine	0
ME	2300311335	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Caswell town	Maine	0
ME	2300311785	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Central Aroostook UT	Maine	0
ME	2300312000	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Chapman town	Maine	0
ME	2300313900	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Connor UT	Maine	0
ME	2300315395	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Crystal town	Maine	0
ME	2300315990	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Cyr plantation	Maine	0
ME	2300319210	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dyer Brook town	Maine	0
ME	2300319420	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Eagle Lake town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2300321380	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Easton town	Maine	0
ME	2300325615	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Fort Fairfield town	Maine	0
ME	2300325755	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Fort Kent town	Maine	0
ME	2300326735	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Frenchville town	Maine	0
ME	2300327120	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Garfield plantation	Maine	0
ME	2300327855	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Glenwood plantation	Maine	0
ME	2300328590	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Grand Isle town	Maine	0
ME	2300330690	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hamlin town	Maine	0
ME	2300330725	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hammond town	Maine	0
ME	2300332195	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Haynesville town	Maine	0
ME	2300332685	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hersey town	Maine	0
ME	2300333385	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hodgdon town	Maine	0
ME	2300333980	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Houlton town	Maine	0
ME	2300335065	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Island Falls town	Maine	0
ME	2300339300	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Limestone town	Maine	0
ME	2300339965	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Linneus town	Maine	0
ME	2300340595	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Littleton town	Maine	0
ME	2300341715	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Ludlow town	Maine	0
ME	2300342450	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Macwahoc plantation	Maine	0
ME	2300342520	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Madawaska town	Maine	0
ME	2300343255	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Mapleton town	Maine	0
ME	2300343710	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Mars Hill town	Maine	0
ME	2300343990	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Masardis town	Maine	0
ME	2300345180	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Merrill town	Maine	0
ME	2300346685	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Monticello town	Maine	0
ME	2300347175	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Moro plantation	Maine	0
ME	2300348120	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Nashville plantation	Maine	0
ME	2300348575	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	New Canada town	Maine	0
ME	2300348960	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	New Limerick town	Maine	0
ME	2300349415	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	New Sweden town	Maine	0
ME	2300353602	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Northwest Aroostook UT	Maine	0
ME	2300354385	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Oakfield town	Maine	0
ME	2300355435	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Orient town	Maine	0
ME	2300356205	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Oxbow plantation	Maine	0
ME	2300357936	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Penobscot Indian Island Reservation	Maine	0
ME	2300358060	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Perham town	Maine	0
ME	2300360300	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Portage Lake town	Maine	0
ME	2300360825	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Presque Isle city	Maine	0
ME	2300362400	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Reed plantation	Maine	0
ME	2300364780	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	St. Agatha town	Maine	0
ME	2300365025	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	St. Francis town	Maine	0
ME	2300365200	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	St. John plantation	Maine	0
ME	2300367790	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Sherman town	Maine	0
ME	2300369260	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Smyrna town	Maine	0
ME	2300369930	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	South Aroostook UT	Maine	0
ME	2300373472	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Square Lake UT	Maine	0
ME	2300374405	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Stockholm town	Maine	0
ME	2300378570	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Van Buren town	Maine	0
ME	2300379270	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Wade town	Maine	0
ME	2300379865	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Wallagrass town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2300380285	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Washburn town	Maine	0
ME	2300382770	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Westfield town	Maine	0
ME	2300383540	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Westmanland town	Maine	0
ME	2300383785	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Weston town	Maine	0
ME	2300386865	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Winterville plantation	Maine	0
ME	2300387215	23	3	NCNTY23003N23003	Aroostook County, ME	Aroostook County	55000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Woodland town	Maine	0
ME	2300502655	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Baldwin town	Maine	1
ME	2300507170	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Bridgton town	Maine	1
ME	2300508430	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Brunswick town	Maine	1
ME	2300510180	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Cape Elizabeth town	Maine	1
ME	2300511125	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Casco town	Maine	1
ME	2300512300	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750		Chebeague Island town	Maine	1
ME	2300515430	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Cumberland town	Maine	1
ME	2300524495	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Falmouth town	Maine	1
ME	2300526525	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Freeport town	Maine	1
ME	2300527025	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Frye Island town	Maine	1
ME	2300528240	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Gorham town	Maine	1
ME	2300528870	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Gray town	Maine	1
ME	2300531390	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Harpswell town	Maine	1
ME	2300531600	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Harrison town	Maine	1
ME	2300541067	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Long Island town	Maine	1
ME	2300548085	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Naples town	Maine	1
ME	2300548820	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	New Gloucester town	Maine	1
ME	2300553860	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	North Yarmouth town	Maine	1
ME	2300560545	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Portland city	Maine	1
ME	2300560685	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Pownal town	Maine	1
ME	2300561945	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Raymond town	Maine	1
ME	2300566145	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Scarborough town	Maine	1
ME	2300566775	23	5	METRO38860N23005	Cumberland County, ME (part) HUD Metro FMR Area	Cumberland County	78100	16450	18800	21150	23450	25350	27250	29100	31000	9999	Sebago town	Maine	1
ME	2300571990	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	South Portland city	Maine	1
ME	2300573670	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Standish town	Maine	1
ME	2300582105	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Westbrook city	Maine	1
ME	2300586025	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Windham town	Maine	1
ME	2300587845	23	5	METRO38860MM6400	Portland, ME HUD Metro FMR Area	Cumberland County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Yarmouth town	Maine	1
ME	2300702235	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Avon town	Maine	0
ME	2300710740	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Carrabassett Valley town	Maine	0
ME	2300710915	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Carthage town	Maine	0
ME	2300712595	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Chesterville town	Maine	0
ME	2300714205	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Coplin plantation	Maine	0
ME	2300716165	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dallas plantation	Maine	0
ME	2300719865	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	East Central Franklin UT	Maine	0
ME	2300724005	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Eustis town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2300724775	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Farmington town	Maine	0
ME	2300734820	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Industry town	Maine	0
ME	2300735625	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Jay town	Maine	0
ME	2300737025	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Kingfield town	Maine	0
ME	2300749345	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	New Sharon town	Maine	0
ME	2300749520	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	New Vineyard town	Maine	0
ME	2300751400	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	North Franklin UT	Maine	0
ME	2300758445	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Phillips town	Maine	0
ME	2300761840	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Rangeley town	Maine	0
ME	2300761875	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Rangeley plantation	Maine	0
ME	2300765655	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Sandy River plantation	Maine	0
ME	2300770760	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	South Franklin UT	Maine	0
ME	2300774825	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Strong town	Maine	0
ME	2300775980	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Temple town	Maine	0
ME	2300781300	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Weld town	Maine	0
ME	2300782235	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	West Central Franklin UT	Maine	0
ME	2300785850	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Wilton town	Maine	0
ME	2300787680	23	7	NCNTY23007N23007	Franklin County, ME	Franklin County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Wyman UT	Maine	0
ME	2300901185	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Amherst town	Maine	0
ME	2300902165	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Aurora town	Maine	0
ME	2300902865	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Bar Harbor town	Maine	0
ME	2300905700	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Blue Hill town	Maine	0
ME	2300907800	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Brooklin town	Maine	0
ME	2300907975	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Brooksville town	Maine	0
ME	2300908815	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Bucksport town	Maine	0
ME	2300911265	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Castine town	Maine	0
ME	2300911800	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Central Hancock UT	Maine	0
ME	2300914905	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Cranberry Isles town	Maine	0
ME	2300916935	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Dedham town	Maine	0
ME	2300917145	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Deer Isle town	Maine	0
ME	2300919770	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Eastbrook town	Maine	0
ME	2300920405	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	East Hancock UT	Maine	0
ME	2300923200	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Ellsworth city	Maine	0
ME	2300926350	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Franklin town	Maine	0
ME	2300926595	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Frenchboro town	Maine	0
ME	2300928450	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Gouldsboro town	Maine	0
ME	2300928975	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Great Pond town	Maine	0
ME	2300930970	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Hancock town	Maine	0
ME	2300938180	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Lamoine town	Maine	0
ME	2300943430	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Mariaville town	Maine	0
ME	2300943578	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Marshall Island UT	Maine	0
ME	2300947630	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Mount Desert town	Maine	0
ME	2300953620	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Northwest Hancock UT	Maine	0
ME	2300955505	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Orland town	Maine	0
ME	2300955855	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Osborn town	Maine	0
ME	2300955890	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Otis town	Maine	0
ME	2300957920	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Penobscot town	Maine	0
ME	2300967300	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Sedgwick town	Maine	0
ME	2300969750	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Sorrento town	Maine	0
ME	2300972865	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Southwest Harbor town	Maine	0
ME	2300974580	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Stonington town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2300974965	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Sullivan town	Maine	0
ME	2300975280	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Surry town	Maine	0
ME	2300975455	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Swans Island town	Maine	0
ME	2300977345	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Tremont town	Maine	0
ME	2300977415	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Trenton town	Maine	0
ME	2300978925	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Verona Island town	Maine	0
ME	2300980040	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Waltham town	Maine	0
ME	2300986655	23	9	NCNTY23009N23009	Hancock County, ME	Hancock County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Winter Harbor town	Maine	0
ME	2301100590	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Albion town	Maine	0
ME	2301102100	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Augusta city	Maine	0
ME	2301104020	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Belgrade town	Maine	0
ME	2301104475	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Benton town	Maine	0
ME	2301112350	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Chelsea town	Maine	0
ME	2301112735	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	China town	Maine	0
ME	2301113470	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Clinton town	Maine	0
ME	2301124670	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Farmingdale town	Maine	0
ME	2301124950	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Fayette town	Maine	0
ME	2301127085	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Gardiner city	Maine	0
ME	2301130550	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Hallowell city	Maine	0
ME	2301140175	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Litchfield town	Maine	0
ME	2301143080	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Manchester town	Maine	0
ME	2301146405	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Monmouth town	Maine	0
ME	2301147770	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Mount Vernon town	Maine	0
ME	2301154560	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Oakland town	Maine	0
ME	2301159110	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Pittston town	Maine	0
ME	2301161700	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Randolph town	Maine	0
ME	2301162190	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Readfield town	Maine	0
ME	2301163835	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Rome town	Maine	0
ME	2301168385	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Sidney town	Maine	0
ME	2301178190	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Unity UT	Maine	0
ME	2301178745	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Vassalboro town	Maine	0
ME	2301179025	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Vienna town	Maine	0
ME	2301180740	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Waterville city	Maine	0
ME	2301180880	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Wayne town	Maine	0
ME	2301182945	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	West Gardiner town	Maine	0
ME	2301186165	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Windsor town	Maine	0
ME	2301186515	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Winslow town	Maine	0
ME	2301186970	23	11	NCNTY23011N23011	Kennebec County, ME	Kennebec County	77700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Winthrop town	Maine	0
ME	2301301465	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Appleton town	Maine	0
ME	2301309725	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Camden town	Maine	0
ME	2301315125	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Criehaven UT	Maine	0
ME	2301315780	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Cushing town	Maine	0
ME	2301326805	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Friendship town	Maine	0
ME	2301333840	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Hope town	Maine	0
ME	2301335135	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Isle au Haut town	Maine	0
ME	2301344165	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Matinicus Isle plantation	Maine	0
ME	2301347962	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Muscle Ridge Island UT	Maine	0
ME	2301351620	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	North Haven town	Maine	0
ME	2301356135	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Owls Head town	Maine	0
ME	2301363590	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Rockland city	Maine	0
ME	2301363660	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Rockport town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2301365130	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	St. George town	Maine	0
ME	2301372585	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	South Thomaston town	Maine	0
ME	2301376365	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Thomaston town	Maine	0
ME	2301378115	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Union town	Maine	0
ME	2301379130	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Vinalhaven town	Maine	0
ME	2301380215	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Warren town	Maine	0
ME	2301380425	23	13	NCNTY23013N23013	Knox County, ME	Knox County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Washington town	Maine	0
ME	2301501010	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Alna town	Maine	0
ME	2301506050	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Boothbay town	Maine	0
ME	2301506120	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Boothbay Harbor town	Maine	0
ME	2301506855	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Bremen town	Maine	0
ME	2301507485	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Bristol town	Maine	0
ME	2301516235	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Damariscotta town	Maine	0
ME	2301518475	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Dresden town	Maine	0
ME	2301522675	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Edgecomb town	Maine	0
ME	2301532715	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Hibberts gore	Maine	0
ME	2301535695	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Jefferson town	Maine	0
ME	2301541280	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Louds Island UT	Maine	0
ME	2301546335	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Monhegan plantation	Maine	0
ME	2301548645	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Newcastle town	Maine	0
ME	2301549660	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Nobleboro town	Maine	0
ME	2301569645	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Somerville town	Maine	0
ME	2301570240	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	South Bristol town	Maine	0
ME	2301571955	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Southport town	Maine	0
ME	2301579550	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Waldoboro town	Maine	0
ME	2301584140	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Westport Island town	Maine	0
ME	2301585010	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Whitefield town	Maine	0
ME	2301587075	23	15	NCNTY23015N23015	Lincoln County, ME	Lincoln County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Wiscasset town	Maine	0
ME	2301701325	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Andover town	Maine	0
ME	2301704825	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Bethel town	Maine	0
ME	2301708150	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Brownfield town	Maine	0
ME	2301708710	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Buckfield town	Maine	0
ME	2301709550	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Byron town	Maine	0
ME	2301710005	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Canton town	Maine	0
ME	2301717250	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Denmark town	Maine	0
ME	2301717740	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dixfield town	Maine	0
ME	2301726910	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Fryeburg town	Maine	0
ME	2301727505	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Gilead town	Maine	0
ME	2301729710	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Greenwood town	Maine	0
ME	2301731110	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hanover town	Maine	0
ME	2301731670	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hartford town	Maine	0
ME	2301732370	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hebron town	Maine	0
ME	2301733315	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hiram town	Maine	0
ME	2301739422	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lincoln plantation	Maine	0
ME	2301741365	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lovell town	Maine	0
ME	2301742835	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Magalloway plantation	Maine	0
ME	2301745285	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Mexico town	Maine	0
ME	2301746105	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Milton UT	Maine	0
ME	2301749275	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Newry town	Maine	0
ME	2301752575	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	North Oxford UT	Maine	0
ME	2301754000	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Norway town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2301755960	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Otisfield town	Maine	0
ME	2301756310	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Oxford town	Maine	0
ME	2301756625	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Paris town	Maine	0
ME	2301758270	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Peru town	Maine	0
ME	2301760405	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Porter town	Maine	0
ME	2301764185	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Roxbury town	Maine	0
ME	2301764290	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Rumford town	Maine	0
ME	2301771755	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	South Oxford UT	Maine	0
ME	2301774510	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Stoneham town	Maine	0
ME	2301774685	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Stow town	Maine	0
ME	2301775035	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Sumner town	Maine	0
ME	2301775595	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Sweden town	Maine	0
ME	2301778465	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Upton town	Maine	0
ME	2301780635	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Waterford town	Maine	0
ME	2301783890	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	West Paris town	Maine	0
ME	2301787355	23	17	NCNTY23017N23017	Oxford County, ME	Oxford County	58400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Woodstock town	Maine	0
ME	2301901115	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Alton town	Maine	1
ME	2301901500	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Argyle UT	Maine	1
ME	2301902795	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Bangor city	Maine	1
ME	2301906575	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Bradford town	Maine	1
ME	2301906680	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Bradley town	Maine	1
ME	2301906925	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Brewer city	Maine	1
ME	2301909200	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Burlington town	Maine	1
ME	2301910670	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Carmel town	Maine	1
ME	2301910810	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Carroll plantation	Maine	1
ME	2301912105	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Charleston town	Maine	1
ME	2301912525	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Chester town	Maine	1
ME	2301913365	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Clifton town	Maine	1
ME	2301914310	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Corinna town	Maine	1
ME	2301914380	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Corinth town	Maine	1
ME	2301917530	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dexter town	Maine	1
ME	2301917950	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dixmont town	Maine	1
ME	2301918580	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Drew plantation	Maine	1
ME	2301919868	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	East Central Penobscot UT	Maine	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2301921030	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	East Millinocket town	Maine	1
ME	2301922535	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Eddington town	Maine	1
ME	2301922710	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Edinburg town	Maine	1
ME	2301923620	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Enfield town	Maine	1
ME	2301923865	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Etna town	Maine	1
ME	2301924110	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Exeter town	Maine	1
ME	2301927190	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Garland town	Maine	1
ME	2301927645	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Glenburn town	Maine	1
ME	2301929185	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Greenbush town	Maine	1
ME	2301930795	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Hampden town	Maine	1
ME	2301932510	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Hermon town	Maine	1
ME	2301933490	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Holden town	Maine	1
ME	2301934190	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Howland town	Maine	1
ME	2301934365	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hudson town	Maine	1
ME	2301936325	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Kenduskeag town	Maine	1
ME	2301937075	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Kingman UT	Maine	1
ME	2301937760	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lagrange town	Maine	1
ME	2301938005	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lakeville town	Maine	1
ME	2301938530	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lee town	Maine	1
ME	2301938705	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Levant town	Maine	1
ME	2301939475	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lincoln town	Maine	1
ME	2301941435	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lowell town	Maine	1
ME	2301944270	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Mattawamkeag town	Maine	1
ME	2301944340	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Maxfield town	Maine	1
ME	2301945005	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Medway town	Maine	1
ME	2301945670	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Milford town	Maine	1
ME	2301945810	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Millinocket town	Maine	1
ME	2301947560	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Mount Chase town	Maine	1
ME	2301948505	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Newburgh town	Maine	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2301949065	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Newport town	Maine	1
ME	2301952710	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	North Penobscot UT	Maine	1
ME	2301955225	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Old Town city	Maine	1
ME	2301955565	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Orono town	Maine	1
ME	2301955680	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Orrington town	Maine	1
ME	2301957045	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Passadumkeag town	Maine	1
ME	2301957150	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Patten town	Maine	1
ME	2301957936	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Penobscot Indian Island Reservation	Maine	1
ME	2301959950	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Plymouth town	Maine	1
ME	2301960790	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Prentiss UT	Maine	1
ME	2301967160	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Seboeis plantation	Maine	1
ME	2301973250	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Springfield town	Maine	1
ME	2301973600	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Stacyville town	Maine	1
ME	2301974055	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Stetson town	Maine	1
ME	2301978015	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Twombly UT	Maine	1
ME	2301978780	23	19	METRO12620MM0730	Bangor, ME HUD Metro FMR Area	Penobscot County	72900	15300	17500	19700	21850	23600	25350	27100	28850	730	Veazie town	Maine	1
ME	2301981055	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Webster plantation	Maine	1
ME	2301985230	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Whitney UT	Maine	1
ME	2301986305	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Winn town	Maine	1
ME	2301987390	23	19	METRO12620N23019	Penobscot County, ME (part) HUD Metro FMR Area	Penobscot County	57400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Woodville town	Maine	1
ME	2302100100	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Abbot town	Maine	0
ME	2302101920	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Atkinson town	Maine	0
ME	2302103740	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Beaver Cove town	Maine	0
ME	2302105560	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Blanchard UT	Maine	0
ME	2302106400	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Bowerbank town	Maine	0
ME	2302108325	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Brownville town	Maine	0
ME	2302118195	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dover-Foxcroft town	Maine	0
ME	2302129535	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Greenville town	Maine	0
ME	2302130095	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Guilford town	Maine	0
ME	2302137095	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Kingsbury plantation	Maine	0
ME	2302137970	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lake View plantation	Maine	0
ME	2302144830	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Medford town	Maine	0
ME	2302146020	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Milo town	Maine	0
ME	2302146580	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Monson town	Maine	0
ME	2302151105	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Northeast Piscataquis UT	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2302153628	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Northwest Piscataquis UT	Maine	0
ME	2302156765	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Parkman town	Maine	0
ME	2302165865	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Sangerville town	Maine	0
ME	2302166950	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Sebec town	Maine	0
ME	2302168140	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Shirley town	Maine	0
ME	2302170655	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Southeast Piscataquis UT	Maine	0
ME	2302181405	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Wellington town	Maine	0
ME	2302185710	23	21	NCNTY23021N23021	Piscataquis County, ME	Piscataquis County	52800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Willimantic town	Maine	0
ME	2302301570	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Arrowsic town	Maine	1
ME	2302303355	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Bath city	Maine	1
ME	2302306260	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Bowdoin town	Maine	1
ME	2302306365	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Bowdoinham town	Maine	1
ME	2302327295	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Georgetown town	Maine	1
ME	2302358070	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Perkins UT	Maine	1
ME	2302358515	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Phippsburg town	Maine	1
ME	2302362645	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Richmond town	Maine	1
ME	2302376960	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Topsham town	Maine	1
ME	2302381930	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	West Bath town	Maine	1
ME	2302387460	23	23	METRO38860N23023	Sagadahoc County, ME HUD Metro FMR Area	Sagadahoc County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Woolwich town	Maine	1
ME	2302501395	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Anson town	Maine	0
ME	2302501885	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Athens town	Maine	0
ME	2302505000	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Bingham town	Maine	0
ME	2302507380	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Brighton plantation	Maine	0
ME	2302509655	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Cambridge town	Maine	0
ME	2302509935	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Canaan town	Maine	0
ME	2302510495	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Caratunk town	Maine	0
ME	2302511820	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Central Somerset UT	Maine	0
ME	2302514555	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Cornville town	Maine	0
ME	2302517285	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dennistown plantation	Maine	0
ME	2302517460	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Detroit town	Maine	0
ME	2302523410	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Embden town	Maine	0
ME	2302524320	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Fairfield town	Maine	0
ME	2302531355	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Harmony town	Maine	0
ME	2302531740	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Hartland town	Maine	0
ME	2302532895	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Highland plantation	Maine	0
ME	2302535345	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Jackman town	Maine	0
ME	2302542660	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Madison town	Maine	0
ME	2302545110	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Mercer town	Maine	0
ME	2302547140	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Moose River town	Maine	0
ME	2302547455	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Moscow town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2302549205	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	New Portland town	Maine	0
ME	2302549835	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Norridgewock town	Maine	0
ME	2302551114	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Northeast Somerset UT	Maine	0
ME	2302553636	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Northwest Somerset UT	Maine	0
ME	2302556520	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Palmyra town	Maine	0
ME	2302559005	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Pittsfield town	Maine	0
ME	2302559705	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Pleasant Ridge plantation	Maine	0
ME	2302562995	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Ripley town	Maine	0
ME	2302564850	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	St. Albans town	Maine	0
ME	2302567238	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Seboomook Lake UT	Maine	0
ME	2302568910	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Skowhegan town	Maine	0
ME	2302569155	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Smithfield town	Maine	0
ME	2302569505	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Solon town	Maine	0
ME	2302573845	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Starks town	Maine	0
ME	2302576190	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	The Forks plantation	Maine	0
ME	2302582840	23	25	NCNTY23025N23025	Somerset County, ME	Somerset County	57500	14150	16200	18200	20200	21850	23450	25050	26700	9999	West Forks plantation	Maine	0
ME	2302703950	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Belfast city	Maine	0
ME	2302704125	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Belmont town	Maine	0
ME	2302707870	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Brooks town	Maine	0
ME	2302709270	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Burnham town	Maine	0
ME	2302726280	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Frankfort town	Maine	0
ME	2302726420	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Freedom town	Maine	0
ME	2302735240	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Islesboro town	Maine	0
ME	2302735450	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Jackson town	Maine	0
ME	2302737585	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Knox town	Maine	0
ME	2302739055	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Liberty town	Maine	0
ME	2302739755	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lincolnville town	Maine	0
ME	2302746475	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Monroe town	Maine	0
ME	2302746790	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Montville town	Maine	0
ME	2302747245	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Morrill town	Maine	0
ME	2302752845	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Northport town	Maine	0
ME	2302756450	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Palermo town	Maine	0
ME	2302761210	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Prospect town	Maine	0
ME	2302766565	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Searsmont town	Maine	0
ME	2302766635	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Searsport town	Maine	0
ME	2302774475	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Stockton Springs town	Maine	0
ME	2302775525	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Swanville town	Maine	0
ME	2302776610	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Thorndike town	Maine	0
ME	2302777625	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Troy town	Maine	0
ME	2302778255	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Unity town	Maine	0
ME	2302779480	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Waldo town	Maine	0
ME	2302786760	23	27	NCNTY23027N23027	Waldo County, ME	Waldo County	65500	14150	16200	18200	20200	21850	23450	25050	26700	730	Winterport town	Maine	0
ME	2302900380	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Addison town	Maine	0
ME	2302900660	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Alexander town	Maine	0
ME	2302902480	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Baileyville town	Maine	0
ME	2302902970	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Baring plantation	Maine	0
ME	2302903670	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Beals town	Maine	0
ME	2302903810	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Beddington town	Maine	0
ME	2302909585	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Calais city	Maine	0
ME	2302912175	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Charlotte town	Maine	0
ME	2302912455	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Cherryfield town	Maine	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2302913610	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Codyville plantation	Maine	0
ME	2302913750	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Columbia town	Maine	0
ME	2302913820	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Columbia Falls town	Maine	0
ME	2302914100	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Cooper town	Maine	0
ME	2302914940	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Crawford town	Maine	0
ME	2302915920	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Cutler town	Maine	0
ME	2302916410	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Danforth town	Maine	0
ME	2302916865	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Deblois town	Maine	0
ME	2302917355	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Dennysville town	Maine	0
ME	2302919870	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	East Central Washington UT	Maine	0
ME	2302920960	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	East Machias town	Maine	0
ME	2302921730	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Eastport city	Maine	0
ME	2302928660	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Grand Lake Stream plantation	Maine	0
ME	2302931530	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Harrington town	Maine	0
ME	2302935905	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Jonesboro town	Maine	0
ME	2302936010	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Jonesport town	Maine	0
ME	2302941610	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lubec town	Maine	0
ME	2302941960	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Machias town	Maine	0
ME	2302942100	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Machiasport town	Maine	0
ME	2302943640	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Marshfield town	Maine	0
ME	2302944760	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Meddybemps town	Maine	0
ME	2302945600	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Milbridge town	Maine	0
ME	2302951375	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Northfield town	Maine	0
ME	2302953500	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	North Washington UT	Maine	0
ME	2302957082	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Passamaquoddy Indian Township Reservation	Maine	0
ME	2302957090	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Passamaquoddy Pleasant Point Reservation	Maine	0
ME	2302957780	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Pembroke town	Maine	0
ME	2302958165	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Perry town	Maine	0
ME	2302961035	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Princeton town	Maine	0
ME	2302963275	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Robbinston town	Maine	0
ME	2302963940	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Roque Bluffs town	Maine	0
ME	2302974125	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Steuben town	Maine	0
ME	2302975770	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Talmadge town	Maine	0
ME	2302976895	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Topsfield town	Maine	0
ME	2302978675	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Vanceboro town	Maine	0
ME	2302979375	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Waite town	Maine	0
ME	2302981685	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Wesley town	Maine	0
ME	2302985185	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Whiting town	Maine	0
ME	2302985290	23	29	NCNTY23029N23029	Washington County, ME	Washington County	53800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Whitneyville town	Maine	0
ME	2303100275	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Acton town	Maine	1
ME	2303100730	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Alfred town	Maine	1
ME	2303101605	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Arundel town	Maine	1
ME	2303104720	23	31	METRO38860MM6450	York-Kittery-South Berwick, ME HUD Metro FMR Area	York County	100700	21150	24200	27200	30200	32650	35050	37450	39900	6450	Berwick town	Maine	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
ME	2303104860	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Biddeford city	Maine	1
ME	2303109410	23	31	METRO38860MM6400	Portland, ME HUD Metro FMR Area	York County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Buxton town	Maine	1
ME	2303114485	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Cornish town	Maine	1
ME	2303116725	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Dayton town	Maine	1
ME	2303122955	23	31	METRO38860MM6450	York-Kittery-South Berwick, ME HUD Metro FMR Area	York County	100700	21150	24200	27200	30200	32650	35050	37450	39900	6450	Eliot town	Maine	1
ME	2303133665	23	31	METRO38860MM6400	Portland, ME HUD Metro FMR Area	York County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Hollis town	Maine	1
ME	2303136535	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Kennebunk town	Maine	1
ME	2303136745	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Kennebunkport town	Maine	1
ME	2303137270	23	31	METRO38860MM6450	York-Kittery-South Berwick, ME HUD Metro FMR Area	York County	100700	21150	24200	27200	30200	32650	35050	37450	39900	6450	Kittery town	Maine	1
ME	2303138425	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Lebanon town	Maine	1
ME	2303139195	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Limerick town	Maine	1
ME	2303139405	23	31	METRO38860MM6400	Portland, ME HUD Metro FMR Area	York County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Limington town	Maine	1
ME	2303141750	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Lyman town	Maine	1
ME	2303148750	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Newfield town	Maine	1
ME	2303150325	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	North Berwick town	Maine	1
ME	2303154980	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Ogunquit town	Maine	1
ME	2303155085	23	31	METRO38860MM6400	Portland, ME HUD Metro FMR Area	York County	100900	21100	24100	27100	30100	32550	34950	37350	39750	6400	Old Orchard Beach town	Maine	1
ME	2303156870	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Parsonsfield town	Maine	1
ME	2303164675	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Saco city	Maine	1
ME	2303165725	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Sanford city	Maine	1
ME	2303167475	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Shapleigh town	Maine	1
ME	2303170030	23	31	METRO38860MM6450	York-Kittery-South Berwick, ME HUD Metro FMR Area	York County	100700	21150	24200	27200	30200	32650	35050	37450	39900	6450	South Berwick town	Maine	1
ME	2303180530	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Waterboro town	Maine	1
ME	2303181475	23	31	METRO38860N23031	York County, ME (part) HUD Metro FMR Area	York County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Wells town	Maine	1
ME	2303187985	23	31	METRO38860MM6450	York-Kittery-South Berwick, ME HUD Metro FMR Area	York County	100700	21150	24200	27200	30200	32650	35050	37450	39900	6450	York town	Maine	1
MD	2400199999	24	1	METRO19060M19060	Cumberland, MD-WV MSA	Allegany County	61900	15300	17500	19700	21850	23600	25350	27100	28850	1900	Allegany County	Maryland	1
MD	2400399999	24	3	METRO12580M12580	Baltimore-Columbia-Towson, MD MSA	Anne Arundel County	104000	21850	25000	28100	31200	33700	36200	38700	41200	720	Anne Arundel County	Maryland	1
MD	2400599999	24	5	METRO12580M12580	Baltimore-Columbia-Towson, MD MSA	Baltimore County	104000	21850	25000	28100	31200	33700	36200	38700	41200	720	Baltimore County	Maryland	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MD	2400999999	24	9	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Calvert County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Calvert County	Maryland	1
MD	2401199999	24	11	NCNTY24011N24011	Caroline County, MD	Caroline County	67500	15300	17500	19700	21850	23600	25350	27100	28850	9999	Caroline County	Maryland	0
MD	2401399999	24	13	METRO12580M12580	Baltimore-Columbia-Towson, MD MSA	Carroll County	104000	21850	25000	28100	31200	33700	36200	38700	41200	720	Carroll County	Maryland	1
MD	2401599999	24	15	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Cecil County	96600	20300	23200	26100	29000	31350	33650	36000	38300	9160	Cecil County	Maryland	1
MD	2401799999	24	17	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Charles County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Charles County	Maryland	1
MD	2401999999	24	19	NCNTY24019N24019	Dorchester County, MD	Dorchester County	68400	15300	17500	19700	21850	23600	25350	27100	28850	9999	Dorchester County	Maryland	0
MD	2402199999	24	21	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Frederick County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Frederick County	Maryland	1
MD	2402399999	24	23	NCNTY24023N24023	Garrett County, MD	Garrett County	61500	15300	17500	19700	21850	23600	25350	27100	28850	9999	Garrett County	Maryland	0
MD	2402599999	24	25	METRO12580M12580	Baltimore-Columbia-Towson, MD MSA	Harford County	104000	21850	25000	28100	31200	33700	36200	38700	41200	720	Harford County	Maryland	1
MD	2402799999	24	27	METRO12580M12580	Baltimore-Columbia-Towson, MD MSA	Howard County	104000	21850	25000	28100	31200	33700	36200	38700	41200	720	Howard County	Maryland	1
MD	2402999999	24	29	NCNTY24029N24029	Kent County, MD	Kent County	78700	16550	18900	21250	23600	25500	27400	29300	31200	9999	Kent County	Maryland	0
MD	2403199999	24	31	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Montgomery County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Montgomery County	Maryland	1
MD	2403399999	24	33	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Prince George's County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Prince George's County	Maryland	1
MD	2403599999	24	35	METRO12580M12580	Baltimore-Columbia-Towson, MD MSA	Queen Anne's County	104000	21850	25000	28100	31200	33700	36200	38700	41200	720	Queen Anne's County	Maryland	1
MD	2403799999	24	37	METRO15680M15680	California-Lexington Park, MD MSA	St. Mary's County	103600	21800	24900	28000	31100	33600	36100	38600	41100	9999	St. Mary's County	Maryland	1
MD	2403999999	24	39	METRO41540N24039	Somerset County, MD HUD Metro FMR Area	Somerset County	54800	15300	17500	19700	21850	23600	25350	27100	28850	9999	Somerset County	Maryland	1
MD	2404199999	24	41	NCNTY24041N24041	Talbot County, MD	Talbot County	85900	18050	20600	23200	25750	27850	29900	31950	34000	9999	Talbot County	Maryland	0
MD	2404399999	24	43	METRO25180MM3180	Hagerstown, MD HUD Metro FMR Area	Washington County	79800	16800	19200	21600	23950	25900	27800	29700	31650	3180	Washington County	Maryland	1
MD	2404599999	24	45	METRO41540M41540	Salisbury, MD HUD Metro FMR Area	Wicomico County	67500	15300	17500	19700	21850	23600	25350	27100	28850	9999	Wicomico County	Maryland	1
MD	2404799999	24	47	METRO41540N24047	Worcester County, MD HUD Metro FMR Area	Worcester County	76000	16000	18250	20550	22800	24650	26450	28300	30100	9999	Worcester County	Maryland	1
MD	2451099999	24	510	METRO12580M12580	Baltimore-Columbia-Towson, MD MSA	Baltimore city	104000	21850	25000	28100	31200	33700	36200	38700	41200	720	Baltimore city	Maryland	1
MA	2500103690	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Barnstable Town city	Massachusetts	1
MA	2500107175	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	9999	Bourne town	Massachusetts	1
MA	2500107980	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Brewster town	Massachusetts	1
MA	2500112995	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Chatham town	Massachusetts	1
MA	2500116775	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Dennis town	Massachusetts	1
MA	2500119295	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Eastham town	Massachusetts	1
MA	2500123105	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	9999	Falmouth town	Massachusetts	1
MA	2500129020	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Harwich town	Massachusetts	1
MA	2500139100	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Mashpee town	Massachusetts	1
MA	2500151440	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Orleans town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2500155500	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	9999	Provincetown town	Massachusetts	1
MA	2500159735	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Sandwich town	Massachusetts	1
MA	2500170605	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	9999	Truro town	Massachusetts	1
MA	2500174385	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	9999	Wellfleet town	Massachusetts	1
MA	2500182525	25	1	METRO12700M12700	Barnstable Town, MA MSA	Barnstable County	96600	20300	23200	26100	29000	31350	33650	36000	38300	740	Yarmouth town	Massachusetts	1
MA	2500300555	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Adams town	Massachusetts	1
MA	2500300975	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Alford town	Massachusetts	1
MA	2500304545	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Becket town	Massachusetts	1
MA	2500313345	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Cheshire town	Massachusetts	1
MA	2500314010	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Clarksburg town	Massachusetts	1
MA	2500316180	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Dalton town	Massachusetts	1
MA	2500321360	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Egremont town	Massachusetts	1
MA	2500324120	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Florida town	Massachusetts	1
MA	2500326815	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Great Barrington town	Massachusetts	1
MA	2500328180	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Hancock town	Massachusetts	1
MA	2500330315	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Hinsdale town	Massachusetts	1
MA	2500334340	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Lanesborough town	Massachusetts	1
MA	2500334655	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Lee town	Massachusetts	1
MA	2500334970	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Lenox town	Massachusetts	1
MA	2500342460	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Monterey town	Massachusetts	1
MA	2500343300	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Mount Washington town	Massachusetts	1
MA	2500344385	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	New Ashford town	Massachusetts	1
MA	2500345420	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	New Marlborough town	Massachusetts	1
MA	2500346225	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	North Adams city	Massachusetts	1
MA	2500351580	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Otis town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2500353050	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Peru town	Massachusetts	1
MA	2500353960	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Pittsfield city	Massachusetts	1
MA	2500356795	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Richmond town	Massachusetts	1
MA	2500359665	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Sandisfield town	Massachusetts	1
MA	2500360225	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Savoy town	Massachusetts	1
MA	2500361065	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Sheffield town	Massachusetts	1
MA	2500367595	25	3	METRO38340M38340	Pittsfield, MA HUD Metro FMR Area	Berkshire County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6320	Stockbridge town	Massachusetts	1
MA	2500371095	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Tyringham town	Massachusetts	1
MA	2500373335	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Washington town	Massachusetts	1
MA	2500377990	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	West Stockbridge town	Massachusetts	1
MA	2500379985	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Williamstown town	Massachusetts	1
MA	2500380685	25	3	METRO38340N25003	Berkshire County, MA (part) HUD Metro FMR Area	Berkshire County	80900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Windsor town	Massachusetts	1
MA	2500500520	25	5	METRO39300MM5400	New Bedford, MA HUD Metro FMR Area	Bristol County	74300	17500	20000	22500	25000	27000	29000	31000	33000	5400	Acushnet town	Massachusetts	1
MA	2500502690	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Attleboro city	Massachusetts	1
MA	2500505280	25	5	METRO39300MM1120	Taunton-Mansfield-Norton, MA HUD Metro FMR Area	Bristol County	111900	22100	25250	28400	31550	34100	36600	39150	41650	1120	Berkley town	Massachusetts	1
MA	2500516425	25	5	METRO39300MM5400	New Bedford, MA HUD Metro FMR Area	Bristol County	74300	17500	20000	22500	25000	27000	29000	31000	33000	5400	Dartmouth town	Massachusetts	1
MA	2500516950	25	5	METRO39300MM1120	Taunton-Mansfield-Norton, MA HUD Metro FMR Area	Bristol County	111900	22100	25250	28400	31550	34100	36600	39150	41650	1120	Dighton town	Massachusetts	1
MA	2500520100	25	5	METRO39300MM1200	Easton-Raynham, MA HUD Metro FMR Area	Bristol County	121300	25500	29150	32800	36400	39350	42250	45150	48050	1200	Easton town	Massachusetts	1
MA	2500522130	25	5	METRO39300MM5400	New Bedford, MA HUD Metro FMR Area	Bristol County	74300	17500	20000	22500	25000	27000	29000	31000	33000	5400	Fairhaven town	Massachusetts	1
MA	2500523000	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Fall River city	Massachusetts	1
MA	2500525240	25	5	METRO39300MM5400	New Bedford, MA HUD Metro FMR Area	Bristol County	74300	17500	20000	22500	25000	27000	29000	31000	33000	5400	Freetown town	Massachusetts	1
MA	2500538225	25	5	METRO39300MM1120	Taunton-Mansfield-Norton, MA HUD Metro FMR Area	Bristol County	111900	22100	25250	28400	31550	34100	36600	39150	41650	1120	Mansfield town	Massachusetts	1
MA	2500545000	25	5	METRO39300MM5400	New Bedford, MA HUD Metro FMR Area	Bristol County	74300	17500	20000	22500	25000	27000	29000	31000	33000	5400	New Bedford city	Massachusetts	1
MA	2500546575	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	North Attleborough town	Massachusetts	1
MA	2500549970	25	5	METRO39300MM1120	Taunton-Mansfield-Norton, MA HUD Metro FMR Area	Bristol County	111900	22100	25250	28400	31550	34100	36600	39150	41650	1120	Norton town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2500556060	25	5	METRO39300MM1200	Easton-Raynham, MA HUD Metro FMR Area	Bristol County	121300	25500	29150	32800	36400	39350	42250	45150	48050	1200	Raynham town	Massachusetts	1
MA	2500556375	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Rehoboth town	Massachusetts	1
MA	2500560645	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Seekonk town	Massachusetts	1
MA	2500562430	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Somerset town	Massachusetts	1
MA	2500568750	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Swansea town	Massachusetts	1
MA	2500569170	25	5	METRO39300MM1120	Taunton-Mansfield-Norton, MA HUD Metro FMR Area	Bristol County	111900	22100	25250	28400	31550	34100	36600	39150	41650	1120	Taunton city	Massachusetts	1
MA	2500577570	25	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Westport town	Massachusetts	1
MA	2500701585	25	7	NCNTY25007N25007	Dukes County, MA	Dukes County	104800	22050	25200	28350	31450	34000	36500	39000	41550	9999	Aquinnah town	Massachusetts	0
MA	2500713800	25	7	NCNTY25007N25007	Dukes County, MA	Dukes County	104800	22050	25200	28350	31450	34000	36500	39000	41550	9999	Chilmark town	Massachusetts	0
MA	2500721150	25	7	NCNTY25007N25007	Dukes County, MA	Dukes County	104800	22050	25200	28350	31450	34000	36500	39000	41550	9999	Edgartown town	Massachusetts	0
MA	2500726325	25	7	NCNTY25007N25007	Dukes County, MA	Dukes County	104800	22050	25200	28350	31450	34000	36500	39000	41550	9999	Gosnold town	Massachusetts	0
MA	2500750390	25	7	NCNTY25007N25007	Dukes County, MA	Dukes County	104800	22050	25200	28350	31450	34000	36500	39000	41550	9999	Oak Bluffs town	Massachusetts	0
MA	2500769940	25	7	NCNTY25007N25007	Dukes County, MA	Dukes County	104800	22050	25200	28350	31450	34000	36500	39000	41550	9999	Tisbury town	Massachusetts	0
MA	2500778235	25	7	NCNTY25007N25007	Dukes County, MA	Dukes County	104800	22050	25200	28350	31450	34000	36500	39000	41550	9999	West Tisbury town	Massachusetts	0
MA	2500901260	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Amesbury Town city	Massachusetts	1
MA	2500901465	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Andover town	Massachusetts	1
MA	2500905595	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Beverly city	Massachusetts	1
MA	2500907420	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Boxford town	Massachusetts	1
MA	2500916250	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Danvers town	Massachusetts	1
MA	2500921850	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Essex town	Massachusetts	1
MA	2500925625	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Georgetown town	Massachusetts	1
MA	2500926150	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Gloucester city	Massachusetts	1
MA	2500927620	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Groveland town	Massachusetts	1
MA	2500927900	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Hamilton town	Massachusetts	1
MA	2500929405	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Haverhill city	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2500932310	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Ipswich town	Massachusetts	1
MA	2500934550	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Lawrence city	Massachusetts	1
MA	2500937490	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Lynn city	Massachusetts	1
MA	2500937560	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Lynnfield town	Massachusetts	1
MA	2500937995	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Manchester-by-the-Sea town	Massachusetts	1
MA	2500938400	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Marblehead town	Massachusetts	1
MA	2500940430	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Merrimac town	Massachusetts	1
MA	2500940710	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Methuen city	Massachusetts	1
MA	2500941095	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Middleton town	Massachusetts	1
MA	2500943580	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Nahant town	Massachusetts	1
MA	2500945175	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Newbury town	Massachusetts	1
MA	2500945245	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Newburyport city	Massachusetts	1
MA	2500946365	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	North Andover town	Massachusetts	1
MA	2500952490	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Peabody city	Massachusetts	1
MA	2500957880	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Rockport town	Massachusetts	1
MA	2500958405	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Rowley town	Massachusetts	1
MA	2500959105	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Salem city	Massachusetts	1
MA	2500959245	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Salisbury town	Massachusetts	1
MA	2500960015	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Saugus town	Massachusetts	1
MA	2500968645	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Swampscott town	Massachusetts	1
MA	2500970150	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Topsfield town	Massachusetts	1
MA	2500974595	25	9	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Essex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Wenham town	Massachusetts	1
MA	2500977150	25	9	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Essex County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	West Newbury town	Massachusetts	1
MA	2501102095	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Ashfield town	Massachusetts	0
MA	2501105560	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Bernardston town	Massachusetts	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2501109595	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Buckland town	Massachusetts	0
MA	2501112505	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Charlemont town	Massachusetts	0
MA	2501114885	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Colrain town	Massachusetts	0
MA	2501115200	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Conway town	Massachusetts	0
MA	2501116670	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Deerfield town	Massachusetts	0
MA	2501121780	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Erving town	Massachusetts	0
MA	2501125730	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Gill town	Massachusetts	0
MA	2501127100	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Greenfield Town city	Massachusetts	0
MA	2501129475	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Hawley town	Massachusetts	0
MA	2501129650	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Heath town	Massachusetts	0
MA	2501135180	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Leverett town	Massachusetts	0
MA	2501135285	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Leyden town	Massachusetts	0
MA	2501142040	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Monroe town	Massachusetts	0
MA	2501142285	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Montague town	Massachusetts	0
MA	2501145490	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	New Salem town	Massachusetts	0
MA	2501147835	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Northfield town	Massachusetts	0
MA	2501151265	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Orange town	Massachusetts	0
MA	2501158335	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Rowe town	Massachusetts	0
MA	2501161135	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Shelburne town	Massachusetts	0
MA	2501161905	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Shutesbury town	Massachusetts	0
MA	2501168400	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	8000	Sunderland town	Massachusetts	0
MA	2501173265	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Warwick town	Massachusetts	0
MA	2501174525	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Wendell town	Massachusetts	0
MA	2501179110	25	11	NCNTY25011N25011	Franklin County, MA HUD Nonmetro FMR Area	Franklin County	80000	17950	20500	23050	25600	27650	29700	31750	33800	9999	Whately town	Massachusetts	0
MA	2501300840	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Agawam Town city	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2501306085	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Blandford town	Massachusetts	1
MA	2501308470	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Brimfield town	Massachusetts	1
MA	2501313485	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Chester town	Massachusetts	1
MA	2501313660	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Chicopee city	Massachusetts	1
MA	2501319645	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	East Longmeadow town	Massachusetts	1
MA	2501326675	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Granville town	Massachusetts	1
MA	2501328075	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Hampden town	Massachusetts	1
MA	2501330665	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9240	Holland town	Massachusetts	1
MA	2501330840	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Holyoke city	Massachusetts	1
MA	2501336300	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Longmeadow town	Massachusetts	1
MA	2501337175	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Ludlow town	Massachusetts	1
MA	2501342145	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Monson town	Massachusetts	1
MA	2501342530	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Montgomery town	Massachusetts	1
MA	2501352144	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Palmer Town city	Massachusetts	1
MA	2501358650	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Russell town	Massachusetts	1
MA	2501365825	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Southwick town	Massachusetts	1
MA	2501367000	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Springfield city	Massachusetts	1
MA	2501370045	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Tolland town	Massachusetts	1
MA	2501372390	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Wales town	Massachusetts	1
MA	2501376030	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Westfield city	Massachusetts	1
MA	2501377890	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	West Springfield Town city	Massachusetts	1
MA	2501379740	25	13	METRO44140M44140	Springfield, MA MSA	Hampden County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Wilbraham town	Massachusetts	1
MA	2501501325	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Amherst town	Massachusetts	1
MA	2501504825	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Belchertown town	Massachusetts	1
MA	2501513590	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Chesterfield town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2501516040	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Cummington town	Massachusetts	1
MA	2501519370	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Easthampton Town city	Massachusetts	1
MA	2501526290	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Goshen town	Massachusetts	1
MA	2501526535	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Granby town	Massachusetts	1
MA	2501527690	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Hadley town	Massachusetts	1
MA	2501529265	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Hatfield town	Massachusetts	1
MA	2501531785	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Huntington town	Massachusetts	1
MA	2501540990	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Middlefield town	Massachusetts	1
MA	2501546330	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Northampton city	Massachusetts	1
MA	2501552560	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Pelham town	Massachusetts	1
MA	2501554030	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Plainfield town	Massachusetts	1
MA	2501562745	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Southampton town	Massachusetts	1
MA	2501564145	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	South Hadley town	Massachusetts	1
MA	2501572880	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Ware town	Massachusetts	1
MA	2501576380	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Westhampton town	Massachusetts	1
MA	2501579915	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	8000	Williamsburg town	Massachusetts	1
MA	2501582175	25	15	METRO44140M44140	Springfield, MA MSA	Hampshire County	77200	17950	20500	23050	25600	27650	29700	31750	33800	9999	Worthington town	Massachusetts	1
MA	2501700380	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Acton town	Massachusetts	1
MA	2501701605	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Arlington town	Massachusetts	1
MA	2501701955	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	2600	Ashby town	Massachusetts	1
MA	2501702130	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Ashland town	Massachusetts	1
MA	2501703005	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Ayer town	Massachusetts	1
MA	2501704615	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Bedford town	Massachusetts	1
MA	2501705070	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Belmont town	Massachusetts	1
MA	2501705805	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Billerica town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2501707350	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Boxborough town	Massachusetts	1
MA	2501709840	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Burlington town	Massachusetts	1
MA	2501711000	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Cambridge city	Massachusetts	1
MA	2501711525	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Carlisle town	Massachusetts	1
MA	2501713135	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Chelmsford town	Massachusetts	1
MA	2501715060	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Concord town	Massachusetts	1
MA	2501717475	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Dracut town	Massachusetts	1
MA	2501717825	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Dunstable town	Massachusetts	1
MA	2501721990	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Everett city	Massachusetts	1
MA	2501724925	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Framingham town	Massachusetts	1
MA	2501727480	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Groton town	Massachusetts	1
MA	2501730700	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Holliston town	Massachusetts	1
MA	2501731085	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Hopkinton town	Massachusetts	1
MA	2501731540	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Hudson town	Massachusetts	1
MA	2501735215	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Lexington town	Massachusetts	1
MA	2501735425	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Lincoln town	Massachusetts	1
MA	2501735950	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Littleton town	Massachusetts	1
MA	2501737000	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Lowell city	Massachusetts	1
MA	2501737875	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Malden city	Massachusetts	1
MA	2501738715	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Marlborough city	Massachusetts	1
MA	2501739625	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Maynard town	Massachusetts	1
MA	2501739835	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Medford city	Massachusetts	1
MA	2501740115	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Melrose city	Massachusetts	1
MA	2501743895	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Natick town	Massachusetts	1
MA	2501745560	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Newton city	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2501748955	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	North Reading town	Massachusetts	1
MA	2501752805	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Pepperell town	Massachusetts	1
MA	2501756130	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Reading town	Massachusetts	1
MA	2501761380	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Sherborn town	Massachusetts	1
MA	2501761590	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Shirley town	Massachusetts	1
MA	2501762535	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Somerville city	Massachusetts	1
MA	2501767665	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Stoneham town	Massachusetts	1
MA	2501768050	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Stow town	Massachusetts	1
MA	2501768260	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Sudbury town	Massachusetts	1
MA	2501769415	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Tewksbury town	Massachusetts	1
MA	2501770360	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Townsend town	Massachusetts	1
MA	2501771025	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Tyngsborough town	Massachusetts	1
MA	2501772215	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Wakefield town	Massachusetts	1
MA	2501772600	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Waltham city	Massachusetts	1
MA	2501773440	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Watertown city	Massachusetts	1
MA	2501773790	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Wayland town	Massachusetts	1
MA	2501776135	25	17	METRO14460MM4560	Lowell, MA HUD Metro FMR Area	Middlesex County	108000	22700	25950	29200	32400	35000	37600	40200	42800	4560	Westford town	Massachusetts	1
MA	2501777255	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Weston town	Massachusetts	1
MA	2501780230	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Wilmington town	Massachusetts	1
MA	2501780510	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Winchester town	Massachusetts	1
MA	2501781035	25	17	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Middlesex County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Woburn city	Massachusetts	1
MA	2501943790	25	19	NCNTY25019N25019	Nantucket County, MA	Nantucket County	116700	24500	28000	31500	35000	37800	40600	43400	46200	9999	Nantucket town	Massachusetts	0
MA	2502102935	25	21	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Norfolk County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Avon town	Massachusetts	1
MA	2502104930	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Bellingham town	Massachusetts	1
MA	2502107740	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Braintree Town city	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2502109175	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Brookline town	Massachusetts	1
MA	2502111315	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Canton town	Massachusetts	1
MA	2502114640	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Cohasset town	Massachusetts	1
MA	2502116495	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Dedham town	Massachusetts	1
MA	2502117405	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Dover town	Massachusetts	1
MA	2502124820	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Foxborough town	Massachusetts	1
MA	2502125172	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Franklin Town city	Massachusetts	1
MA	2502130455	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Holbrook town	Massachusetts	1
MA	2502139765	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Medfield town	Massachusetts	1
MA	2502139975	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Medway town	Massachusetts	1
MA	2502141515	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Millis town	Massachusetts	1
MA	2502141690	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Milton town	Massachusetts	1
MA	2502144105	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Needham town	Massachusetts	1
MA	2502146050	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Norfolk town	Massachusetts	1
MA	2502150250	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Norwood town	Massachusetts	1
MA	2502154100	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Plainville town	Massachusetts	1
MA	2502155745	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Quincy city	Massachusetts	1
MA	2502155955	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Randolph town	Massachusetts	1
MA	2502160785	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Sharon town	Massachusetts	1
MA	2502167945	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Stoughton town	Massachusetts	1
MA	2502172495	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Walpole town	Massachusetts	1
MA	2502174175	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Wellesley town	Massachusetts	1
MA	2502178690	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Westwood town	Massachusetts	1
MA	2502178972	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Weymouth Town city	Massachusetts	1
MA	2502182315	25	21	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Norfolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Wrentham town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2502300170	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Abington town	Massachusetts	1
MA	2502308085	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Bridgewater town	Massachusetts	1
MA	2502309000	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Brockton city	Massachusetts	1
MA	2502311665	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Carver town	Massachusetts	1
MA	2502317895	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Duxbury town	Massachusetts	1
MA	2502318455	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	East Bridgewater town	Massachusetts	1
MA	2502327795	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Halifax town	Massachusetts	1
MA	2502328285	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Hanover town	Massachusetts	1
MA	2502328495	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Hanson town	Massachusetts	1
MA	2502330210	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Hingham town	Massachusetts	1
MA	2502331645	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Hull town	Massachusetts	1
MA	2502333220	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Kingston town	Massachusetts	1
MA	2502333920	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Lakeville town	Massachusetts	1
MA	2502338540	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	5400	Marion town	Massachusetts	1
MA	2502338855	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Marshfield town	Massachusetts	1
MA	2502339450	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	5400	Mattapoisett town	Massachusetts	1
MA	2502340850	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Middleborough town	Massachusetts	1
MA	2502350145	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Norwell town	Massachusetts	1
MA	2502352630	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Pembroke town	Massachusetts	1
MA	2502354310	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Plymouth town	Massachusetts	1
MA	2502354415	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Plympton town	Massachusetts	1
MA	2502357600	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	5400	Rochester town	Massachusetts	1
MA	2502357775	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Rockland town	Massachusetts	1
MA	2502360330	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Scituate town	Massachusetts	1
MA	2502372985	25	23	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Plymouth County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Wareham town	Massachusetts	1

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MA	2502375260	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	West Bridgewater town	Massachusetts	1
MA	2502379530	25	23	METRO14460MM1200	Brockton, MA HUD Metro FMR Area	Plymouth County	95200	20000	22850	25700	28550	30850	33150	35450	37700	1200	Whitman town	Massachusetts	1
MA	2502507000	25	25	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Suffolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Boston city	Massachusetts	1
MA	2502513205	25	25	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Suffolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Chelsea city	Massachusetts	1
MA	2502556585	25	25	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Suffolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Revere city	Massachusetts	1
MA	2502581005	25	25	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Suffolk County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Winthrop Town city	Massachusetts	1
MA	2502701885	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Ashburnham town	Massachusetts	1
MA	2502702480	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Athol town	Massachusetts	1
MA	2502702760	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Auburn town	Massachusetts	1
MA	2502703740	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Barre town	Massachusetts	1
MA	2502705490	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Berlin town	Massachusetts	1
MA	2502706015	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Blackstone town	Massachusetts	1
MA	2502706365	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Bolton town	Massachusetts	1
MA	2502707525	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Boylston town	Massachusetts	1
MA	2502709105	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Brookfield town	Massachusetts	1
MA	2502712715	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Charlton town	Massachusetts	1
MA	2502714395	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Clinton town	Massachusetts	1
MA	2502717300	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Douglas town	Massachusetts	1
MA	2502717685	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Dudley town	Massachusetts	1
MA	2502718560	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	East Brookfield town	Massachusetts	1
MA	2502723875	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Fitchburg city	Massachusetts	1
MA	2502725485	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Gardner city	Massachusetts	1
MA	2502726430	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Grafton town	Massachusetts	1
MA	2502728740	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Hardwick town	Massachusetts	1
MA	2502728950	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Harvard town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2502730560	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Holden town	Massachusetts	1
MA	2502730945	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Hopedale town	Massachusetts	1
MA	2502731435	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Hubbardston town	Massachusetts	1
MA	2502734165	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Lancaster town	Massachusetts	1
MA	2502734795	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Leicester town	Massachusetts	1
MA	2502735075	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Leominster city	Massachusetts	1
MA	2502737420	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Lunenburg town	Massachusetts	1
MA	2502740255	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Mendon town	Massachusetts	1
MA	2502741165	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Milford town	Massachusetts	1
MA	2502741340	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Millbury town	Massachusetts	1
MA	2502741585	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Millville town	Massachusetts	1
MA	2502745105	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	New Braintree town	Massachusetts	1
MA	2502746820	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Northborough town	Massachusetts	1
MA	2502746925	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Northbridge town	Massachusetts	1
MA	2502747135	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	North Brookfield town	Massachusetts	1
MA	2502750670	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Oakham town	Massachusetts	1
MA	2502751825	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Oxford town	Massachusetts	1
MA	2502752420	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Paxton town	Massachusetts	1
MA	2502753120	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Petersham town	Massachusetts	1
MA	2502753225	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Phillipston town	Massachusetts	1
MA	2502755395	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Princeton town	Massachusetts	1
MA	2502758580	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Royalston town	Massachusetts	1
MA	2502758825	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Rutland town	Massachusetts	1
MA	2502761800	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Shrewsbury town	Massachusetts	1
MA	2502763165	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Southborough town	Massachusetts	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MA	2502763345	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Southbridge Town city	Massachusetts	1
MA	2502766105	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Spencer town	Massachusetts	1
MA	2502767385	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Sterling town	Massachusetts	1
MA	2502768155	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Sturbridge town	Massachusetts	1
MA	2502768610	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Sutton town	Massachusetts	1
MA	2502769275	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Templeton town	Massachusetts	1
MA	2502771480	25	27	METRO49340MM1120	Eastern Worcester County, MA HUD Metro FMR Area	Worcester County	111600	23450	26800	30150	33500	36200	38900	41550	44250	1120	Upton town	Massachusetts	1
MA	2502771620	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Uxbridge town	Massachusetts	1
MA	2502773090	25	27	METRO49340N25027	Western Worcester County, MA HUD Metro FMR Area	Worcester County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Warren town	Massachusetts	1
MA	2502773895	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Webster town	Massachusetts	1
MA	2502775015	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Westborough town	Massachusetts	1
MA	2502775155	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	West Boylston town	Massachusetts	1
MA	2502775400	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	West Brookfield town	Massachusetts	1
MA	2502777010	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Westminster town	Massachusetts	1
MA	2502780405	25	27	METRO49340MM2600	Fitchburg-Leominster, MA HUD Metro FMR Area	Worcester County	83200	17950	20500	23050	25600	27650	29700	31750	33800	2600	Winchendon town	Massachusetts	1
MA	2502782000	25	27	METRO49340M49340	Worcester, MA HUD Metro FMR Area	Worcester County	98200	20650	23600	26550	29450	31850	34200	36550	38900	9240	Worcester city	Massachusetts	1
MI	2600199999	26	1	NCNTY26001N26001	Alcona County, MI	Alcona County	52200	13450	15350	17250	19150	20700	22250	23750	25300	9999	Alcona County	Michigan	0
MI	2600399999	26	3	NCNTY26003N26003	Alger County, MI	Alger County	60000	13450	15350	17250	19150	20700	22250	23750	25300	9999	Alger County	Michigan	0
MI	2600599999	26	5	NCNTY26005N26005	Allegan County, MI	Allegan County	78700	16350	18700	21050	23350	25250	27100	29000	30850	3000	Allegan County	Michigan	0
MI	2600799999	26	7	NCNTY26007N26007	Alpena County, MI	Alpena County	56800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Alpena County	Michigan	0
MI	2600999999	26	9	NCNTY26009N26009	Antrim County, MI	Antrim County	64500	13550	15500	17450	19350	20900	22450	24000	25550	9999	Antrim County	Michigan	0
MI	2601199999	26	11	NCNTY26011N26011	Arenac County, MI	Arenac County	52700	13450	15350	17250	19150	20700	22250	23750	25300	9999	Arenac County	Michigan	0
MI	2601399999	26	13	NCNTY26013N26013	Baraga County, MI	Baraga County	55700	13450	15350	17250	19150	20700	22250	23750	25300	9999	Baraga County	Michigan	0
MI	2601599999	26	15	METRO24340N26015	Barry County, MI HUD Metro FMR Area	Barry County	72000	15150	17300	19450	21600	23350	25100	26800	28550	9999	Barry County	Michigan	1
MI	2601799999	26	17	METRO13020M13020	Bay City, MI MSA	Bay County	59500	13450	15350	17250	19150	20700	22250	23750	25300	6960	Bay County	Michigan	1
MI	2601999999	26	19	NCNTY26019N26019	Benzie County, MI	Benzie County	69400	14500	16550	18600	20650	22350	24000	25650	27300	9999	Benzie County	Michigan	0
MI	2602199999	26	21	METRO35660M35660	Niles-Benton Harbor, MI MSA	Berrien County	61000	13450	15350	17250	19150	20700	22250	23750	25300	870	Berrien County	Michigan	1
MI	2602399999	26	23	NCNTY26023N26023	Branch County, MI	Branch County	61100	13450	15350	17250	19150	20700	22250	23750	25300	9999	Branch County	Michigan	0
MI	2602599999	26	25	METRO12980M12980	Battle Creek, MI MSA	Calhoun County	61100	13450	15350	17250	19150	20700	22250	23750	25300	3720	Calhoun County	Michigan	1
MI	2602799999	26	27	METRO43780N26027	Cass County, MI HUD Metro FMR Area	Cass County	65900	13850	15800	17800	19750	21350	22950	24500	26100	9999	Cass County	Michigan	1
MI	2602999999	26	29	NCNTY26029N26029	Charlevoix County, MI	Charlevoix County	68400	14350	16400	18450	20500	22150	23800	25450	27100	9999	Charlevoix County	Michigan	0
MI	2603199999	26	31	NCNTY26031N26031	Cheboygan County, MI	Cheboygan County	55600	13450	15350	17250	19150	20700	22250	23750	25300	9999	Cheboygan County	Michigan	0
MI	2603399999	26	33	NCNTY26033N26033	Chippewa County, MI	Chippewa County	56900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Chippewa County	Michigan	0
MI	2603599999	26	35	NCNTY26035N26035	Clare County, MI	Clare County	48000	13450	15350	17250	19150	20700	22250	23750	25300	9999	Clare County	Michigan	0
MI	2603799999	26	37	METRO29620M29620	Lansing-East Lansing, MI MSA	Clinton County	80700	16850	19250	21650	24050	26000	27900	29850	31750	4040	Clinton County	Michigan	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MI	2603999999	26	39	NCNTY26039N26039	Crawford County, MI	Crawford County	54900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Crawford County	Michigan	0
MI	2604199999	26	41	NCNTY26041N26041	Delta County, MI	Delta County	60300	13450	15350	17250	19150	20700	22250	23750	25300	9999	Delta County	Michigan	0
MI	2604399999	26	43	NCNTY26043N26043	Dickinson County, MI	Dickinson County	59800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Dickinson County	Michigan	0
MI	2604599999	26	45	METRO29620M29620	Lansing-East Lansing, MI MSA	Eaton County	80700	16850	19250	21650	24050	26000	27900	29850	31750	4040	Eaton County	Michigan	1
MI	2604799999	26	47	NCNTY26047N26047	Emmet County, MI	Emmet County	70600	14850	17000	19100	21200	22900	24600	26300	28000	9999	Emmet County	Michigan	0
MI	2604999999	26	49	METRO22420M22420	Flint, MI MSA	Genesee County	62400	13450	15350	17250	19150	20700	22250	23750	25300	2640	Genesee County	Michigan	1
MI	2605199999	26	51	NCNTY26051N26051	Gladwin County, MI	Gladwin County	53800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Gladwin County	Michigan	0
MI	2605399999	26	53	NCNTY26053N26053	Gogebic County, MI	Gogebic County	54500	13450	15350	17250	19150	20700	22250	23750	25300	9999	Gogebic County	Michigan	0
MI	2605599999	26	55	NCNTY26055N26055	Grand Traverse County, MI	Grand Traverse County	81000	17050	19450	21900	24300	26250	28200	30150	32100	9999	Grand Traverse County	Michigan	0
MI	2605799999	26	57	NCNTY26057N26057	Gratiot County, MI	Gratiot County	55200	13450	15350	17250	19150	20700	22250	23750	25300	9999	Gratiot County	Michigan	0
MI	2605999999	26	59	NCNTY26059N26059	Hillsdale County, MI	Hillsdale County	60800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Hillsdale County	Michigan	0
MI	2606199999	26	61	NCNTY26061N26061	Houghton County, MI	Houghton County	62400	13450	15350	17250	19150	20700	22250	23750	25300	9999	Houghton County	Michigan	0
MI	2606399999	26	63	NCNTY26063N26063	Huron County, MI	Huron County	60500	13450	15350	17250	19150	20700	22250	23750	25300	9999	Huron County	Michigan	0
MI	2606599999	26	65	METRO29620M29620	Lansing-East Lansing, MI MSA	Ingham County	80700	16850	19250	21650	24050	26000	27900	29850	31750	4040	Ingham County	Michigan	1
MI	2606799999	26	67	NCNTY26067N26067	Ionia County, MI	Ionia County	65100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Ionia County	Michigan	0
MI	2606999999	26	69	NCNTY26069N26069	Iosco County, MI	Iosco County	52800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Iosco County	Michigan	0
MI	2607199999	26	71	NCNTY26071N26071	Iron County, MI	Iron County	55600	13450	15350	17250	19150	20700	22250	23750	25300	9999	Iron County	Michigan	0
MI	2607399999	26	73	NCNTY26073N26073	Isabella County, MI	Isabella County	66200	13850	15800	17800	19750	21350	22950	24500	26100	9999	Isabella County	Michigan	0
MI	2607599999	26	75	METRO27100M27100	Jackson, MI MSA	Jackson County	66400	13950	15950	17950	19900	21500	23100	24700	26300	3520	Jackson County	Michigan	1
MI	2607799999	26	77	METRO28020M28020	Kalamazoo-Portage, MI MSA	Kalamazoo County	79000	16600	19000	21350	23700	25600	27500	29400	31300	3720	Kalamazoo County	Michigan	1
MI	2607999999	26	79	NCNTY26079N26079	Kalkaska County, MI	Kalkaska County	53000	13450	15350	17250	19150	20700	22250	23750	25300	9999	Kalkaska County	Michigan	0
MI	2608199999	26	81	METRO24340M24340	Grand Rapids-Wyoming, MI HUD Metro FMR Area	Kent County	80200	16850	19250	21650	24050	26000	27900	29850	31750	3000	Kent County	Michigan	1
MI	2608399999	26	83	NCNTY26083N26083	Keweenaw County, MI	Keweenaw County	55800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Keweenaw County	Michigan	0
MI	2608599999	26	85	NCNTY26085N26085	Lake County, MI	Lake County	46100	13450	15350	17250	19150	20700	22250	23750	25300	9999	Lake County	Michigan	0
MI	2608799999	26	87	METRO19820M19820	Detroit-Warren-Livonia, MI HUD Metro FMR Area	Lapeer County	78500	16500	18850	21200	23550	25450	27350	29250	31100	2160	Lapeer County	Michigan	1
MI	2608999999	26	89	NCNTY26089N26089	Leelanau County, MI	Leelanau County	78600	16550	18900	21250	23600	25500	27400	29300	31200	9999	Leelanau County	Michigan	0
MI	2609199999	26	91	NCNTY26091N26091	Lenawee County, MI	Lenawee County	70300	14750	16850	18950	21050	22750	24450	26150	27800	440	Lenawee County	Michigan	0
MI	2609399999	26	93	METRO19820MM0440	Livingston County, MI HUD Metro FMR Area	Livingston County	101700	21350	24400	27450	30500	32950	35400	37850	40300	440	Livingston County	Michigan	1
MI	2609599999	26	95	NCNTY26095N26095	Luce County, MI	Luce County	54400	13450	15350	17250	19150	20700	22250	23750	25300	9999	Luce County	Michigan	0
MI	2609799999	26	97	NCNTY26097N26097	Mackinac County, MI	Mackinac County	54500	13450	15350	17250	19150	20700	22250	23750	25300	9999	Mackinac County	Michigan	0
MI	2609999999	26	99	METRO19820M19820	Detroit-Warren-Livonia, MI HUD Metro FMR Area	Macomb County	78500	16500	18850	21200	23550	25450	27350	29250	31100	2160	Macomb County	Michigan	1
MI	2610199999	26	101	NCNTY26101N26101	Manistee County, MI	Manistee County	58100	13450	15350	17250	19150	20700	22250	23750	25300	9999	Manistee County	Michigan	0
MI	2610399999	26	103	NCNTY26103N26103	Marquette County, MI	Marquette County	63300	13850	15800	17800	19750	21350	22950	24500	26100	9999	Marquette County	Michigan	0
MI	2610599999	26	105	NCNTY26105N26105	Mason County, MI	Mason County	59100	13450	15350	17250	19150	20700	22250	23750	25300	9999	Mason County	Michigan	0
MI	2610799999	26	107	NCNTY26107N26107	Mecosta County, MI	Mecosta County	59500	13450	15350	17250	19150	20700	22250	23750	25300	9999	Mecosta County	Michigan	0
MI	2610999999	26	109	NCNTY26109N26109	Menominee County, MI	Menominee County	58400	13450	15350	17250	19150	20700	22250	23750	25300	9999	Menominee County	Michigan	0
MI	2611199999	26	111	METRO33220M33220	Midland, MI MSA	Midland County	82200	16950	19350	21750	24150	26100	28050	29950	31900	6960	Midland County	Michigan	1
MI	2611399999	26	113	NCNTY26113N26113	Missaukee County, MI	Missaukee County	53400	13450	15350	17250	19150	20700	22250	23750	25300	9999	Missaukee County	Michigan	0
MI	2611599999	26	115	METRO33780M33780	Monroe, MI MSA	Monroe County	80600	16950	19400	21800	24200	26150	28100	30050	31950	2160	Monroe County	Michigan	1
MI	2611799999	26	117	METRO24340N26117	Montcalm County, MI HUD Metro FMR Area	Montcalm County	55700	13450	15350	17250	19150	20700	22250	23750	25300	9999	Montcalm County	Michigan	1
MI	2611999999	26	119	NCNTY26119N26119	Montmorency County, MI	Montmorency County	48400	13450	15350	17250	19150	20700	22250	23750	25300	9999	Montmorency County	Michigan	0
MI	2612199999	26	121	METRO34740M34740	Muskegon, MI MSA	Muskegon County	62900	13450	15350	17250	19150	20700	22250	23750	25300	3000	Muskegon County	Michigan	1
MI	2612399999	26	123	NCNTY26123N26123	Newaygo County, MI	Newaygo County	57000	13450	15350	17250	19150	20700	22250	23750	25300	9999	Newaygo County	Michigan	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MI	2612599999	26	125	METRO19820M19820	Detroit-Warren-Livonia, MI HUD Metro FMR Area	Oakland County	78500	16500	18850	21200	23550	25450	27350	29250	31100	2160	Oakland County	Michigan	1
MI	2612799999	26	127	NCNTY26127N26127	Oceana County, MI	Oceana County	54100	13450	15350	17250	19150	20700	22250	23750	25300	9999	Oceana County	Michigan	0
MI	2612999999	26	129	NCNTY26129N26129	Ogemaw County, MI	Ogemaw County	50100	13450	15350	17250	19150	20700	22250	23750	25300	9999	Ogemaw County	Michigan	0
MI	2613199999	26	131	NCNTY26131N26131	Ontonagon County, MI	Ontonagon County	49800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Ontonagon County	Michigan	0
MI	2613399999	26	133	NCNTY26133N26133	Osceola County, MI	Osceola County	52500	13450	15350	17250	19150	20700	22250	23750	25300	9999	Osceola County	Michigan	0
MI	2613599999	26	135	NCNTY26135N26135	Oscoda County, MI	Oscoda County	49700	13450	15350	17250	19150	20700	22250	23750	25300	9999	Oscoda County	Michigan	0
MI	2613799999	26	137	NCNTY26137N26137	Otsego County, MI	Otsego County	63100	13450	15350	17250	19150	20700	22250	23750	25300	9999	Otsego County	Michigan	0
MI	2613999999	26	139	METRO24340M26100	Holland-Grand Haven, MI HUD Metro FMR Area	Ottawa County	83600	17600	20100	22600	25100	27150	29150	31150	33150	3000	Ottawa County	Michigan	1
MI	2614199999	26	141	NCNTY26141N26141	Presque Isle County, MI	Presque Isle County	55000	13450	15350	17250	19150	20700	22250	23750	25300	9999	Presque Isle County	Michigan	0
MI	2614399999	26	143	NCNTY26143N26143	Roscommon County, MI	Roscommon County	47400	13450	15350	17250	19150	20700	22250	23750	25300	9999	Roscommon County	Michigan	0
MI	2614599999	26	145	METRO40980M40980	Saginaw, MI MSA	Saginaw County	62900	13450	15350	17250	19150	20700	22250	23750	25300	6960	Saginaw County	Michigan	1
MI	2614799999	26	147	METRO19820M19820	Detroit-Warren-Livonia, MI HUD Metro FMR Area	St. Clair County	78500	16500	18850	21200	23550	25450	27350	29250	31100	2160	St. Clair County	Michigan	1
MI	2614999999	26	149	NCNTY26149N26149	St. Joseph County, MI	St. Joseph County	60100	13450	15350	17250	19150	20700	22250	23750	25300	9999	St. Joseph County	Michigan	0
MI	2615199999	26	151	NCNTY26151N26151	Sanilac County, MI	Sanilac County	56600	13450	15350	17250	19150	20700	22250	23750	25300	9999	Sanilac County	Michigan	0
MI	2615399999	26	153	NCNTY26153N26153	Schoolcraft County, MI	Schoolcraft County	53300	13450	15350	17250	19150	20700	22250	23750	25300	9999	Schoolcraft County	Michigan	0
MI	2615599999	26	155	NCNTY26155N26155	Shiawassee County, MI	Shiawassee County	71100	14700	16800	18900	20950	22650	24350	26000	27700	9999	Shiawassee County	Michigan	0
MI	2615799999	26	157	NCNTY26157N26157	Tuscola County, MI	Tuscola County	58400	13450	15350	17250	19150	20700	22250	23750	25300	9999	Tuscola County	Michigan	0
MI	2615999999	26	159	METRO28020M28020	Kalamazoo-Portage, MI MSA	Van Buren County	79000	16600	19000	21350	23700	25600	27500	29400	31300	3720	Van Buren County	Michigan	1
MI	2616199999	26	161	METRO11460M11460	Ann Arbor, MI MSA	Washtenaw County	101500	21350	24400	27450	30450	32900	35350	37800	40200	440	Washtenaw County	Michigan	1
MI	2616399999	26	163	METRO19820M19820	Detroit-Warren-Livonia, MI HUD Metro FMR Area	Wayne County	78500	16500	18850	21200	23550	25450	27350	29250	31100	2160	Wayne County	Michigan	1
MI	2616599999	26	165	NCNTY26165N26165	Wexford County, MI	Wexford County	52900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Wexford County	Michigan	0
MN	2700199999	27	1	NCNTY27001N27001	Aitkin County, MN	Aitkin County	59200	15300	17450	19650	21800	23550	25300	27050	28800	9999	Aitkin County	Minnesota	0
MN	2700399999	27	3	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Anoka County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Anoka County	Minnesota	1
MN	2700599999	27	5	NCNTY27005N27005	Becker County, MN	Becker County	71900	15300	17450	19650	21800	23550	25300	27050	28800	9999	Becker County	Minnesota	0
MN	2700799999	27	7	NCNTY27007N27007	Beltrami County, MN	Beltrami County	60900	15300	17450	19650	21800	23550	25300	27050	28800	9999	Beltrami County	Minnesota	0
MN	2700999999	27	9	METRO41060M41060	St. Cloud, MN MSA	Benton County	81200	17050	19500	21950	24350	26300	28250	30200	32150	6980	Benton County	Minnesota	1
MN	2701199999	27	11	NCNTY27011N27011	Big Stone County, MN	Big Stone County	70200	15300	17450	19650	21800	23550	25300	27050	28800	9999	Big Stone County	Minnesota	0
MN	2701399999	27	13	METRO31860M31860	Mankato-North Mankato, MN MSA	Blue Earth County	86200	17800	20350	22900	25400	27450	29500	31500	33550	9999	Blue Earth County	Minnesota	1
MN	2701599999	27	15	NCNTY27015N27015	Brown County, MN	Brown County	76400	16050	18350	20650	22900	24750	26600	28400	30250	9999	Brown County	Minnesota	0
MN	2701799999	27	17	METRO20260M20260	Duluth, MN-WI MSA	Carlton County	76800	16150	18450	20750	23050	24900	26750	28600	30450	9999	Carlton County	Minnesota	1
MN	2701999999	27	19	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Carver County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Carver County	Minnesota	1
MN	2702199999	27	21	NCNTY27021N27021	Cass County, MN	Cass County	61500	15300	17450	19650	21800	23550	25300	27050	28800	9999	Cass County	Minnesota	0
MN	2702399999	27	23	NCNTY27023N27023	Chippewa County, MN	Chippewa County	73300	15400	17600	19800	22000	23800	25550	27300	29050	9999	Chippewa County	Minnesota	0
MN	2702599999	27	25	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Chisago County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Chisago County	Minnesota	1
MN	2702799999	27	27	METRO22020M22020	Fargo, ND-MN MSA	Clay County	89400	18800	21450	24150	26800	28950	31100	33250	35400	2520	Clay County	Minnesota	1
MN	2702999999	27	29	NCNTY27029N27029	Clearwater County, MN	Clearwater County	61600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Clearwater County	Minnesota	0
MN	2703199999	27	31	NCNTY27031N27031	Cook County, MN	Cook County	65100	15300	17450	19650	21800	23550	25300	27050	28800	9999	Cook County	Minnesota	0
MN	2703399999	27	33	NCNTY27033N27033	Cottonwood County, MN	Cottonwood County	67200	15300	17450	19650	21800	23550	25300	27050	28800	9999	Cottonwood County	Minnesota	0
MN	2703599999	27	35	NCNTY27035N27035	Crow Wing County, MN	Crow Wing County	69600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Crow Wing County	Minnesota	0
MN	2703799999	27	37	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Dakota County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Dakota County	Minnesota	1
MN	2703999999	27	39	METRO40340M40340	Rochester, MN HUD Metro FMR Area	Dodge County	103000	21250	24300	27350	30350	32800	35250	37650	40100	9999	Dodge County	Minnesota	1
MN	2704199999	27	41	NCNTY27041N27041	Douglas County, MN	Douglas County	79400	16700	19050	21450	23800	25750	27650	29550	31450	9999	Douglas County	Minnesota	0
MN	2704399999	27	43	NCNTY27043N27043	Faribault County, MN	Faribault County	67200	15300	17450	19650	21800	23550	25300	27050	28800	9999	Faribault County	Minnesota	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MN	2704599999	27	45	METRO40340N27045	Fillmore County, MN HUD Metro FMR Area	Fillmore County	75900	15950	18200	20500	22750	24600	26400	28250	30050	9999	Fillmore County	Minnesota	1
MN	2704799999	27	47	NCNTY27047N27047	Freeborn County, MN	Freeborn County	66000	15300	17450	19650	21800	23550	25300	27050	28800	9999	Freeborn County	Minnesota	0
MN	2704999999	27	49	NCNTY27049N27049	Goodhue County, MN	Goodhue County	86800	18250	20850	23450	26050	28150	30250	32350	34400	9999	Goodhue County	Minnesota	0
MN	2705199999	27	51	NCNTY27051N27051	Grant County, MN	Grant County	65900	15300	17450	19650	21800	23550	25300	27050	28800	9999	Grant County	Minnesota	0
MN	2705399999	27	53	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Hennepin County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Hennepin County	Minnesota	1
MN	2705599999	27	55	METRO29100M29100	La Crosse-Onalaska, WI-MN MSA	Houston County	76800	16150	18450	20750	23050	24900	26750	28600	30450	3870	Houston County	Minnesota	1
MN	2705799999	27	57	NCNTY27057N27057	Hubbard County, MN	Hubbard County	68800	15300	17450	19650	21800	23550	25300	27050	28800	9999	Hubbard County	Minnesota	0
MN	2705999999	27	59	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Isanti County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Isanti County	Minnesota	1
MN	2706199999	27	61	NCNTY27061N27061	Itasca County, MN	Itasca County	65000	15300	17450	19650	21800	23550	25300	27050	28800	9999	Itasca County	Minnesota	0
MN	2706399999	27	63	NCNTY27063N27063	Jackson County, MN	Jackson County	74900	15750	18000	20250	22450	24250	26050	27850	29650	9999	Jackson County	Minnesota	0
MN	2706599999	27	65	NCNTY27065N27065	Kanabec County, MN	Kanabec County	64400	15300	17450	19650	21800	23550	25300	27050	28800	9999	Kanabec County	Minnesota	0
MN	2706799999	27	67	NCNTY27067N27067	Kandiyohi County, MN	Kandiyohi County	73400	15400	17600	19800	22000	23800	25550	27300	29050	9999	Kandiyohi County	Minnesota	0
MN	2706999999	27	69	NCNTY27069N27069	Kittson County, MN	Kittson County	73100	15400	17600	19800	21950	23750	25500	27250	29000	9999	Kittson County	Minnesota	0
MN	2707199999	27	71	NCNTY27071N27071	Koochiching County, MN	Koochiching County	65300	15300	17450	19650	21800	23550	25300	27050	28800	9999	Koochiching County	Minnesota	0
MN	2707399999	27	73	NCNTY27073N27073	Lac qui Parle County, MN	Lac qui Parle County	66100	15300	17450	19650	21800	23550	25300	27050	28800	9999	Lac qui Parle County	Minnesota	0
MN	2707599999	27	75	NCNTY27075N27075	Lake County, MN	Lake County	73900	15550	17750	19950	22150	23950	25700	27500	29250	9999	Lake County	Minnesota	0
MN	2707799999	27	77	NCNTY27077N27077	Lake of the Woods County, MN	Lake of the Woods County	70900	15300	17450	19650	21800	23550	25300	27050	28800	9999	Lake of the Woods County	Minnesota	0
MN	2707999999	27	79	METRO33460N27079	Le Sueur County, MN HUD Metro FMR Area	Le Sueur County	84700	17800	20350	22900	25400	27450	29500	31500	33550	9999	Le Sueur County	Minnesota	1
MN	2708199999	27	81	NCNTY27081N27081	Lincoln County, MN	Lincoln County	71700	15300	17450	19650	21800	23550	25300	27050	28800	9999	Lincoln County	Minnesota	0
MN	2708399999	27	83	NCNTY27083N27083	Lyon County, MN	Lyon County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Lyon County	Minnesota	0
MN	2708599999	27	85	NCNTY27085N27085	McLeod County, MN	McLeod County	76400	16050	18350	20650	22900	24750	26600	28400	30250	9999	McLeod County	Minnesota	0
MN	2708799999	27	87	NCNTY27087N27087	Mahnomen County, MN	Mahnomen County	55200	15300	17450	19650	21800	23550	25300	27050	28800	9999	Mahnomen County	Minnesota	0
MN	2708999999	27	89	NCNTY27089N27089	Marshall County, MN	Marshall County	76000	16000	18250	20550	22800	24650	26450	28300	30100	9999	Marshall County	Minnesota	0
MN	2709199999	27	91	NCNTY27091N27091	Martin County, MN	Martin County	70900	15300	17450	19650	21800	23550	25300	27050	28800	9999	Martin County	Minnesota	0
MN	2709399999	27	93	NCNTY27093N27093	Meeker County, MN	Meeker County	76700	16100	18400	20700	23000	24850	26700	28550	30400	9999	Meeker County	Minnesota	0
MN	2709599999	27	95	METRO33460N27095	Mille Lacs County, MN HUD Metro FMR Area	Mille Lacs County	65200	15300	17450	19650	21800	23550	25300	27050	28800	9999	Mille Lacs County	Minnesota	1
MN	2709799999	27	97	NCNTY27097N27097	Morrison County, MN	Morrison County	70400	15300	17450	19650	21800	23550	25300	27050	28800	9999	Morrison County	Minnesota	0
MN	2709999999	27	99	NCNTY27099N27099	Mower County, MN	Mower County	73700	15500	17700	19900	22100	23900	25650	27450	29200	9999	Mower County	Minnesota	0
MN	2710199999	27	101	NCNTY27101N27101	Murray County, MN	Murray County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Murray County	Minnesota	0
MN	2710399999	27	103	METRO31860M31860	Mankato-North Mankato, MN MSA	Nicollet County	86200	17800	20350	22900	25400	27450	29500	31500	33550	9999	Nicollet County	Minnesota	1
MN	2710599999	27	105	NCNTY27105N27105	Nobles County, MN	Nobles County	68000	15300	17450	19650	21800	23550	25300	27050	28800	9999	Nobles County	Minnesota	0
MN	2710799999	27	107	NCNTY27107N27107	Norman County, MN	Norman County	67900	15300	17450	19650	21800	23550	25300	27050	28800	9999	Norman County	Minnesota	0
MN	2710999999	27	109	METRO40340M40340	Rochester, MN HUD Metro FMR Area	Olmsted County	103000	21250	24300	27350	30350	32800	35250	37650	40100	6820	Olmsted County	Minnesota	1
MN	2711199999	27	111	NCNTY27111N27111	Otter Tail County, MN	Otter Tail County	72400	15300	17450	19650	21800	23550	25300	27050	28800	9999	Otter Tail County	Minnesota	0
MN	2711399999	27	113	NCNTY27113N27113	Pennington County, MN	Pennington County	73300	15400	17600	19800	22000	23800	25550	27300	29050	9999	Pennington County	Minnesota	0
MN	2711599999	27	115	NCNTY27115N27115	Pine County, MN	Pine County	62300	15300	17450	19650	21800	23550	25300	27050	28800	9999	Pine County	Minnesota	0
MN	2711799999	27	117	NCNTY27117N27117	Pipestone County, MN	Pipestone County	65800	15300	17450	19650	21800	23550	25300	27050	28800	9999	Pipestone County	Minnesota	0
MN	2711999999	27	119	METRO24220M24220	Grand Forks, ND-MN MSA	Polk County	89200	18550	21200	23850	26500	28650	30750	32900	35000	2985	Polk County	Minnesota	1
MN	2712199999	27	121	NCNTY27121N27121	Pope County, MN	Pope County	77400	16250	18600	20900	23200	25100	26950	28800	30650	9999	Pope County	Minnesota	0
MN	2712399999	27	123	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Ramsey County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Ramsey County	Minnesota	1
MN	2712599999	27	125	NCNTY27125N27125	Red Lake County, MN	Red Lake County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Red Lake County	Minnesota	0
MN	2712799999	27	127	NCNTY27127N27127	Redwood County, MN	Redwood County	69800	15300	17450	19650	21800	23550	25300	27050	28800	9999	Redwood County	Minnesota	0
MN	2712999999	27	129	NCNTY27129N27129	Renville County, MN	Renville County	73300	15400	17600	19800	22000	23800	25550	27300	29050	9999	Renville County	Minnesota	0
MN	2713199999	27	131	NCNTY27131N27131	Rice County, MN	Rice County	82400	17300	19800	22250	24700	26700	28700	30650	32650	9999	Rice County	Minnesota	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MN	2713399999	27	133	NCNTY27133N27133	Rock County, MN	Rock County	70300	15300	17450	19650	21800	23550	25300	27050	28800	9999	Rock County	Minnesota	0
MN	2713599999	27	135	NCNTY27135N27135	Roseau County, MN	Roseau County	72300	15300	17450	19650	21800	23550	25300	27050	28800	9999	Roseau County	Minnesota	0
MN	2713799999	27	137	METRO20260M20260	Duluth, MN-WI MSA	St. Louis County	76800	16150	18450	20750	23050	24900	26750	28600	30450	2240	St. Louis County	Minnesota	1
MN	2713999999	27	139	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Scott County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Scott County	Minnesota	1
MN	2714199999	27	141	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Sherburne County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Sherburne County	Minnesota	1
MN	2714399999	27	143	METRO33460N27143	Sibley County, MN HUD Metro FMR Area	Sibley County	74800	15750	18000	20250	22450	24250	26050	27850	29650	9999	Sibley County	Minnesota	1
MN	2714599999	27	145	METRO41060M41060	St. Cloud, MN MSA	Stearns County	81200	17050	19500	21950	24350	26300	28250	30200	32150	6980	Stearns County	Minnesota	1
MN	2714799999	27	147	NCNTY27147N27147	Steele County, MN	Steele County	80900	17000	19400	21850	24250	26200	28150	30100	32050	9999	Steele County	Minnesota	0
MN	2714999999	27	149	NCNTY27149N27149	Stevens County, MN	Stevens County	85000	17600	20100	22600	25100	27150	29150	31150	33150	9999	Stevens County	Minnesota	0
MN	2715199999	27	151	NCNTY27151N27151	Swift County, MN	Swift County	66600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Swift County	Minnesota	0
MN	2715399999	27	153	NCNTY27153N27153	Todd County, MN	Todd County	63200	15300	17450	19650	21800	23550	25300	27050	28800	9999	Todd County	Minnesota	0
MN	2715599999	27	155	NCNTY27155N27155	Traverse County, MN	Traverse County	66800	15300	17450	19650	21800	23550	25300	27050	28800	9999	Traverse County	Minnesota	0
MN	2715799999	27	157	METRO40340N27157	Wabasha County, MN HUD Metro FMR Area	Wabasha County	77600	16350	18650	21000	23300	25200	27050	28900	30800	9999	Wabasha County	Minnesota	1
MN	2715999999	27	159	NCNTY27159N27159	Wadena County, MN	Wadena County	59000	15300	17450	19650	21800	23550	25300	27050	28800	9999	Wadena County	Minnesota	0
MN	2716199999	27	161	NCNTY27161N27161	Waseca County, MN	Waseca County	75200	15800	18050	20300	22550	24400	26200	28000	29800	9999	Waseca County	Minnesota	0
MN	2716399999	27	163	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Washington County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Washington County	Minnesota	1
MN	2716599999	27	165	NCNTY27165N27165	Watonwan County, MN	Watonwan County	66800	15300	17450	19650	21800	23550	25300	27050	28800	9999	Watonwan County	Minnesota	0
MN	2716799999	27	167	NCNTY27167N27167	Wilkin County, MN	Wilkin County	71000	15300	17450	19650	21800	23550	25300	27050	28800	9999	Wilkin County	Minnesota	0
MN	2716999999	27	169	NCNTY27169N27169	Winona County, MN	Winona County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Winona County	Minnesota	0
MN	2717199999	27	171	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Wright County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Wright County	Minnesota	1
MN	2717399999	27	173	NCNTY27173N27173	Yellow Medicine County, MN	Yellow Medicine County	70400	15300	17450	19650	21800	23550	25300	27050	28800	9999	Yellow Medicine County	Minnesota	0
MS	2800199999	28	1	NCNTY28001N28001	Adams County, MS	Adams County	37200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Adams County	Mississippi	0
MS	2800399999	28	3	NCNTY28003N28003	Alcorn County, MS	Alcorn County	49200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Alcorn County	Mississippi	0
MS	2800599999	28	5	NCNTY28005N28005	Amite County, MS	Amite County	46100	11100	12650	14250	15800	17100	18350	19600	20900	9999	Amite County	Mississippi	0
MS	2800799999	28	7	NCNTY28007N28007	Attala County, MS	Attala County	47400	11100	12650	14250	15800	17100	18350	19600	20900	9999	Attala County	Mississippi	0
MS	2800999999	28	9	METRO32820N28009	Benton County, MS HUD Metro FMR Area	Benton County	48600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Benton County	Mississippi	1
MS	2801199999	28	11	NCNTY28011N28011	Bolivar County, MS	Bolivar County	38500	11100	12650	14250	15800	17100	18350	19600	20900	9999	Bolivar County	Mississippi	0
MS	2801399999	28	13	NCNTY28013N28013	Calhoun County, MS	Calhoun County	45900	11100	12650	14250	15800	17100	18350	19600	20900	9999	Calhoun County	Mississippi	0
MS	2801599999	28	15	NCNTY28015N28015	Carroll County, MS	Carroll County	60900	12650	14450	16250	18050	19500	20950	22400	23850	9999	Carroll County	Mississippi	0
MS	2801799999	28	17	NCNTY28017N28017	Chickasaw County, MS	Chickasaw County	47000	11100	12650	14250	15800	17100	18350	19600	20900	9999	Chickasaw County	Mississippi	0
MS	2801999999	28	19	NCNTY28019N28019	Choctaw County, MS	Choctaw County	52600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Choctaw County	Mississippi	0
MS	2802199999	28	21	NCNTY28021N28021	Claiborne County, MS	Claiborne County	29600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Claiborne County	Mississippi	0
MS	2802399999	28	23	NCNTY28023N28023	Clarke County, MS	Clarke County	54100	11350	12950	14550	16150	17450	18750	20050	21350	9999	Clarke County	Mississippi	0
MS	2802599999	28	25	NCNTY28025N28025	Clay County, MS	Clay County	44800	11100	12650	14250	15800	17100	18350	19600	20900	9999	Clay County	Mississippi	0
MS	2802799999	28	27	NCNTY28027N28027	Coahoma County, MS	Coahoma County	35300	11100	12650	14250	15800	17100	18350	19600	20900	9999	Coahoma County	Mississippi	0
MS	2802999999	28	29	METRO27140M27140	Jackson, MS HUD Metro FMR Area	Copiah County	70900	14900	17000	19150	21250	22950	24650	26350	28050	9999	Copiah County	Mississippi	1
MS	2803199999	28	31	NCNTY28031N28031	Covington County, MS	Covington County	46600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Covington County	Mississippi	0
MS	2803399999	28	33	METRO32820M32820	Memphis, TN-MS-AR HUD Metro FMR Area	DeSoto County	67900	14250	16300	18350	20350	22000	23650	25250	26900	4920	DeSoto County	Mississippi	1
MS	2803599999	28	35	METRO25620M25620	Hattiesburg, MS MSA	Forrest County	62600	13200	15050	16950	18800	20350	21850	23350	24850	3285	Forrest County	Mississippi	1
MS	2803799999	28	37	NCNTY28037N28037	Franklin County, MS	Franklin County	57000	12000	13700	15400	17100	18500	19850	21250	22600	9999	Franklin County	Mississippi	0
MS	2803999999	28	39	NCNTY28039N28039	George County, MS	George County	60700	12750	14600	16400	18200	19700	21150	22600	24050	9999	George County	Mississippi	0
MS	2804199999	28	41	NCNTY28041N28041	Greene County, MS	Greene County	64100	12800	14600	16450	18250	19750	21200	22650	24100	9999	Greene County	Mississippi	0
MS	2804399999	28	43	NCNTY28043N28043	Grenada County, MS	Grenada County	45700	11100	12650	14250	15800	17100	18350	19600	20900	9999	Grenada County	Mississippi	0
MS	2804599999	28	45	METRO25060M25060	Gulfport-Biloxi, MS HUD Metro FMR Area	Hancock County	60900	12800	14600	16450	18250	19750	21200	22650	24100	920	Hancock County	Mississippi	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MS	2804799999	28	47	METRO25060M25060	Gulfport-Biloxi, MS HUD Metro FMR Area	Harrison County	60900	12800	14600	16450	18250	19750	21200	22650	24100	920	Harrison County	Mississippi	1
MS	2804999999	28	49	METRO27140M27140	Jackson, MS HUD Metro FMR Area	Hinds County	70900	14900	17000	19150	21250	22950	24650	26350	28050	3560	Hinds County	Mississippi	1
MS	2805199999	28	51	NCNTY28051N28051	Holmes County, MS	Holmes County	26200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Holmes County	Mississippi	0
MS	2805399999	28	53	NCNTY28053N28053	Humphreys County, MS	Humphreys County	33300	11100	12650	14250	15800	17100	18350	19600	20900	9999	Humphreys County	Mississippi	0
MS	2805599999	28	55	NCNTY28055N28055	Issaquena County, MS	Issaquena County	32200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Issaquena County	Mississippi	0
MS	2805799999	28	57	NCNTY28057N28057	Itawamba County, MS	Itawamba County	52800	11100	12700	14300	15850	17150	18400	19700	20950	9999	Itawamba County	Mississippi	0
MS	2805999999	28	59	METRO25060M37700	Pascagoula, MS HUD Metro FMR Area	Jackson County	69100	14550	16600	18700	20750	22450	24100	25750	27400	920	Jackson County	Mississippi	1
MS	2806199999	28	61	NCNTY28061N28061	Jasper County, MS	Jasper County	46500	11100	12650	14250	15800	17100	18350	19600	20900	9999	Jasper County	Mississippi	0
MS	2806399999	28	63	NCNTY28063N28063	Jefferson County, MS	Jefferson County	32200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Jefferson County	Mississippi	0
MS	2806599999	28	65	NCNTY28065N28065	Jefferson Davis County, MS	Jefferson Davis County	34100	11100	12650	14250	15800	17100	18350	19600	20900	9999	Jefferson Davis County	Mississippi	0
MS	2806799999	28	67	NCNTY28067N28067	Jones County, MS	Jones County	48400	11100	12650	14250	15800	17100	18350	19600	20900	9999	Jones County	Mississippi	0
MS	2806999999	28	69	NCNTY28069N28069	Kemper County, MS	Kemper County	39900	11100	12650	14250	15800	17100	18350	19600	20900	9999	Kemper County	Mississippi	0
MS	2807199999	28	71	NCNTY28071N28071	Lafayette County, MS	Lafayette County	72400	15200	17400	19550	21700	23450	25200	26950	28650	9999	Lafayette County	Mississippi	0
MS	2807399999	28	73	METRO25620M25620	Hattiesburg, MS MSA	Lamar County	62600	13200	15050	16950	18800	20350	21850	23350	24850	3285	Lamar County	Mississippi	1
MS	2807599999	28	75	NCNTY28075N28075	Lauderdale County, MS	Lauderdale County	63200	11750	13400	15100	16750	18100	19450	20800	22150	9999	Lauderdale County	Mississippi	0
MS	2807799999	28	77	NCNTY28077N28077	Lawrence County, MS	Lawrence County	56400	11300	12900	14500	16100	17400	18700	20000	21300	9999	Lawrence County	Mississippi	0
MS	2807999999	28	79	NCNTY28079N28079	Leake County, MS	Leake County	49400	11100	12650	14250	15800	17100	18350	19600	20900	9999	Leake County	Mississippi	0
MS	2808199999	28	81	NCNTY28081N28081	Lee County, MS	Lee County	71800	13600	15550	17500	19400	21000	22550	24100	25650	9999	Lee County	Mississippi	0
MS	2808399999	28	83	NCNTY28083N28083	Leflore County, MS	Leflore County	32200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Leflore County	Mississippi	0
MS	2808599999	28	85	NCNTY28085N28085	Lincoln County, MS	Lincoln County	50400	11100	12650	14250	15800	17100	18350	19600	20900	9999	Lincoln County	Mississippi	0
MS	2808799999	28	87	NCNTY28087N28087	Lowndes County, MS	Lowndes County	58300	12250	14000	15750	17500	18900	20300	21700	23100	9999	Lowndes County	Mississippi	0
MS	2808999999	28	89	METRO27140M27140	Jackson, MS HUD Metro FMR Area	Madison County	70900	14900	17000	19150	21250	22950	24650	26350	28050	3560	Madison County	Mississippi	1
MS	2809199999	28	91	NCNTY28091N28091	Marion County, MS	Marion County	41900	11100	12650	14250	15800	17100	18350	19600	20900	9999	Marion County	Mississippi	0
MS	2809399999	28	93	METRO32820N28093	Marshall County, MS HUD Metro FMR Area	Marshall County	53800	11200	12800	14400	16000	17300	18600	19850	21150	9999	Marshall County	Mississippi	1
MS	2809599999	28	95	NCNTY28095N28095	Monroe County, MS	Monroe County	54600	11500	13150	14800	16400	17750	19050	20350	21650	9999	Monroe County	Mississippi	0
MS	2809799999	28	97	NCNTY28097N28097	Montgomery County, MS	Montgomery County	44700	11100	12650	14250	15800	17100	18350	19600	20900	9999	Montgomery County	Mississippi	0
MS	2809999999	28	99	NCNTY28099N28099	Neshoba County, MS	Neshoba County	50900	11100	12650	14250	15800	17100	18350	19600	20900	9999	Neshoba County	Mississippi	0
MS	2810199999	28	101	NCNTY28101N28101	Newton County, MS	Newton County	49500	11100	12650	14250	15800	17100	18350	19600	20900	9999	Newton County	Mississippi	0
MS	2810399999	28	103	NCNTY28103N28103	Noxubee County, MS	Noxubee County	46600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Noxubee County	Mississippi	0
MS	2810599999	28	105	NCNTY28105N28105	Oktibbeha County, MS	Oktibbeha County	61800	13000	14850	16700	18550	20050	21550	23050	24500	9999	Oktibbeha County	Mississippi	0
MS	2810799999	28	107	NCNTY28107N28107	Panola County, MS	Panola County	44500	11100	12650	14250	15800	17100	18350	19600	20900	9999	Panola County	Mississippi	0
MS	2810999999	28	109	NCNTY28109N28109	Pearl River County, MS	Pearl River County	60300	12700	14500	16300	18100	19550	21000	22450	23900	9999	Pearl River County	Mississippi	0
MS	2811199999	28	111	METRO25620M25620	Hattiesburg, MS MSA	Perry County	62600	13200	15050	16950	18800	20350	21850	23350	24850	9999	Perry County	Mississippi	1
MS	2811399999	28	113	NCNTY28113N28113	Pike County, MS	Pike County	43300	11100	12650	14250	15800	17100	18350	19600	20900	9999	Pike County	Mississippi	0
MS	2811599999	28	115	NCNTY28115N28115	Pontotoc County, MS	Pontotoc County	53900	11350	12950	14550	16150	17450	18750	20050	21350	9999	Pontotoc County	Mississippi	0
MS	2811799999	28	117	NCNTY28117N28117	Prentiss County, MS	Prentiss County	47000	11100	12650	14250	15800	17100	18350	19600	20900	9999	Prentiss County	Mississippi	0
MS	2811999999	28	119	NCNTY28119N28119	Quitman County, MS	Quitman County	37100	11100	12650	14250	15800	17100	18350	19600	20900	9999	Quitman County	Mississippi	0
MS	2812199999	28	121	METRO27140M27140	Jackson, MS HUD Metro FMR Area	Rankin County	70900	14900	17000	19150	21250	22950	24650	26350	28050	3560	Rankin County	Mississippi	1
MS	2812399999	28	123	NCNTY28123N28123	Scott County, MS	Scott County	43300	11100	12650	14250	15800	17100	18350	19600	20900	9999	Scott County	Mississippi	0
MS	2812599999	28	125	NCNTY28125N28125	Sharkey County, MS	Sharkey County	43300	11100	12650	14250	15800	17100	18350	19600	20900	9999	Sharkey County	Mississippi	0
MS	2812799999	28	127	METRO27140N28127	Simpson County, MS HUD Metro FMR Area	Simpson County	44900	11100	12650	14250	15800	17100	18350	19600	20900	9999	Simpson County	Mississippi	1
MS	2812999999	28	129	NCNTY28129N28129	Smith County, MS	Smith County	54500	11450	13100	14750	16350	17700	19000	20300	21600	9999	Smith County	Mississippi	0
MS	2813199999	28	131	NCNTY28131N28131	Stone County, MS	Stone County	59000	12400	14200	15950	17700	19150	20550	21950	23400	9999	Stone County	Mississippi	0
MS	2813399999	28	133	NCNTY28133N28133	Sunflower County, MS	Sunflower County	37600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Sunflower County	Mississippi	0
MS	2813599999	28	135	NCNTY28135N28135	Tallahatchie County, MS	Tallahatchie County	42200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Tallahatchie County	Mississippi	0
MS	2813799999	28	137	METRO32820N28137	Tate County, MS HUD Metro FMR Area	Tate County	62100	13100	14950	16800	18650	20150	21650	23150	24650	9999	Tate County	Mississippi	1
MS	2813999999	28	139	NCNTY28139N28139	Tippah County, MS	Tippah County	51300	11100	12650	14250	15800	17100	18350	19600	20900	9999	Tippah County	Mississippi	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MS	2814199999	28	141	NCNTY28141N28141	Tishomingo County, MS	Tishomingo County	47400	11100	12650	14250	15800	17100	18350	19600	20900	9999	Tishomingo County	Mississippi	0
MS	2814399999	28	143	METRO32820N28143	Tunica County, MS HUD Metro FMR Area	Tunica County	39300	11100	12650	14250	15800	17100	18350	19600	20900	9999	Tunica County	Mississippi	1
MS	2814599999	28	145	NCNTY28145N28145	Union County, MS	Union County	51200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Union County	Mississippi	0
MS	2814799999	28	147	NCNTY28147N28147	Walthall County, MS	Walthall County	43000	11100	12650	14250	15800	17100	18350	19600	20900	9999	Walthall County	Mississippi	0
MS	2814999999	28	149	NCNTY28149N28149	Warren County, MS	Warren County	54900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Warren County	Mississippi	0
MS	2815199999	28	151	NCNTY28151N28151	Washington County, MS	Washington County	40700	11100	12650	14250	15800	17100	18350	19600	20900	9999	Washington County	Mississippi	0
MS	2815399999	28	153	NCNTY28153N28153	Wayne County, MS	Wayne County	53800	11350	12950	14550	16150	17450	18750	20050	21350	9999	Wayne County	Mississippi	0
MS	2815599999	28	155	NCNTY28155N28155	Webster County, MS	Webster County	52600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Webster County	Mississippi	0
MS	2815799999	28	157	NCNTY28157N28157	Wilkinson County, MS	Wilkinson County	33600	11100	12650	14250	15800	17100	18350	19600	20900	9999	Wilkinson County	Mississippi	0
MS	2815999999	28	159	NCNTY28159N28159	Winston County, MS	Winston County	46100	11100	12650	14250	15800	17100	18350	19600	20900	9999	Winston County	Mississippi	0
MS	2816199999	28	161	NCNTY28161N28161	Yalobusha County, MS	Yalobusha County	48200	11100	12650	14250	15800	17100	18350	19600	20900	9999	Yalobusha County	Mississippi	0
MS	2816399999	28	163	METRO27140N28163	Yazoo County, MS HUD Metro FMR Area	Yazoo County	39900	11100	12650	14250	15800	17100	18350	19600	20900	9999	Yazoo County	Mississippi	1
MO	2900199999	29	1	NCNTY29001N29001	Adair County, MO	Adair County	65000	13650	15600	17550	19500	21100	22650	24200	25750	9999	Adair County	Missouri	0
MO	2900399999	29	3	METRO41140M41140	St. Joseph, MO-KS MSA	Andrew County	63600	13400	15300	17200	19100	20650	22200	23700	25250	7000	Andrew County	Missouri	1
MO	2900599999	29	5	NCNTY29005N29005	Atchison County, MO	Atchison County	63900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Atchison County	Missouri	0
MO	2900799999	29	7	NCNTY29007N29007	Audrain County, MO	Audrain County	58600	12350	14100	15850	17600	19050	20450	21850	23250	9999	Audrain County	Missouri	0
MO	2900999999	29	9	NCNTY29009N29009	Barry County, MO	Barry County	54400	11800	13500	15200	16850	18200	19550	20900	22250	9999	Barry County	Missouri	0
MO	2901199999	29	11	NCNTY29011N29011	Barton County, MO	Barton County	54200	11800	13500	15200	16850	18200	19550	20900	22250	9999	Barton County	Missouri	0
MO	2901399999	29	13	METRO28140N29013	Bates County, MO HUD Metro FMR Area	Bates County	63700	13300	15200	17100	18950	20500	22000	23500	25050	9999	Bates County	Missouri	1
MO	2901599999	29	15	NCNTY29015N29015	Benton County, MO	Benton County	45300	11800	13500	15200	16850	18200	19550	20900	22250	9999	Benton County	Missouri	0
MO	2901799999	29	17	METRO16020M16020	Cape Girardeau, MO-IL MSA	Bollinger County	67000	14100	16100	18100	20100	21750	23350	24950	26550	9999	Bollinger County	Missouri	1
MO	2901999999	29	19	METRO17860M17860	Columbia, MO MSA	Boone County	77900	16350	18700	21050	23350	25250	27100	29000	30850	1740	Boone County	Missouri	1
MO	2902199999	29	21	METRO41140M41140	St. Joseph, MO-KS MSA	Buchanan County	63600	13400	15300	17200	19100	20650	22200	23700	25250	7000	Buchanan County	Missouri	1
MO	2902399999	29	23	NCNTY29023N29023	Butler County, MO	Butler County	49400	11800	13500	15200	16850	18200	19550	20900	22250	9999	Butler County	Missouri	0
MO	2902599999	29	25	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Caldwell County	86000	18100	20650	23250	25800	27900	29950	32000	34100	9999	Caldwell County	Missouri	1
MO	2902799999	29	27	METRO27620N29027	Callaway County, MO HUD Metro FMR Area	Callaway County	69500	14600	16700	18800	20850	22550	24200	25900	27550	9999	Callaway County	Missouri	1
MO	2902999999	29	29	NCNTY29029N29029	Camden County, MO	Camden County	63000	13250	15150	17050	18900	20450	21950	23450	24950	9999	Camden County	Missouri	0
MO	2903199999	29	31	METRO16020M16020	Cape Girardeau, MO-IL MSA	Cape Girardeau County	67000	14100	16100	18100	20100	21750	23350	24950	26550	9999	Cape Girardeau County	Missouri	1
MO	2903399999	29	33	NCNTY29033N29033	Carroll County, MO	Carroll County	60700	12750	14600	16400	18200	19700	21150	22600	24050	9999	Carroll County	Missouri	0
MO	2903599999	29	35	NCNTY29035N29035	Carter County, MO	Carter County	52800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Carter County	Missouri	0
MO	2903799999	29	37	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Cass County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Cass County	Missouri	1
MO	2903999999	29	39	NCNTY29039N29039	Cedar County, MO	Cedar County	47100	11800	13500	15200	16850	18200	19550	20900	22250	9999	Cedar County	Missouri	0
MO	2904199999	29	41	NCNTY29041N29041	Chariton County, MO	Chariton County	56000	11800	13500	15200	16850	18200	19550	20900	22250	9999	Chariton County	Missouri	0
MO	2904399999	29	43	METRO44180M44180	Springfield, MO HUD Metro FMR Area	Christian County	65300	13750	15700	17650	19600	21200	22750	24350	25900	7920	Christian County	Missouri	1
MO	2904599999	29	45	NCNTY29045N29045	Clark County, MO	Clark County	58000	12200	13950	15700	17400	18800	20200	21600	23000	9999	Clark County	Missouri	0
MO	2904799999	29	47	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Clay County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Clay County	Missouri	1
MO	2904999999	29	49	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Clinton County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Clinton County	Missouri	1
MO	2905199999	29	51	METRO27620M27620	Jefferson City, MO HUD Metro FMR Area	Cole County	75500	15900	18150	20400	22650	24500	26300	28100	29900	9999	Cole County	Missouri	1
MO	2905399999	29	53	NCNTY29053N29053	Cooper County, MO	Cooper County	67100	14150	16150	18150	20150	21800	23400	25000	26600	9999	Cooper County	Missouri	0
MO	2905599999	29	55	NCNTY29055N29055	Crawford County, MO	Crawford County	52300	11800	13500	15200	16850	18200	19550	20900	22250	9999	Crawford County	Missouri	0
MO	2905699999	29	55	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Sullivan part	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Sullivan city part of Crawford County	Missouri	1
MO	2905799999	29	57	NCNTY29057N29057	Dade County, MO	Dade County	48700	11800	13500	15200	16850	18200	19550	20900	22250	9999	Dade County	Missouri	0
MO	2905999999	29	59	METRO44180N29059	Dallas County, MO HUD Metro FMR Area	Dallas County	49500	11800	13500	15200	16850	18200	19550	20900	22250	9999	Dallas County	Missouri	1
MO	2906199999	29	61	NCNTY29061N29061	Daviess County, MO	Daviess County	63200	12900	14750	16600	18400	19900	21350	22850	24300	9999	Daviess County	Missouri	0
MO	2906399999	29	63	METRO41140M41140	St. Joseph, MO-KS MSA	DeKalb County	63600	13400	15300	17200	19100	20650	22200	23700	25250	9999	DeKalb County	Missouri	1
MO	2906599999	29	65	NCNTY29065N29065	Dent County, MO	Dent County	51500	11800	13500	15200	16850	18200	19550	20900	22250	9999	Dent County	Missouri	0
MO	2906799999	29	67	NCNTY29067N29067	Douglas County, MO	Douglas County	41700	11800	13500	15200	16850	18200	19550	20900	22250	9999	Douglas County	Missouri	0
MO	2906999999	29	69	NCNTY29069N29069	Dunklin County, MO	Dunklin County	42800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Dunklin County	Missouri	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MO	2907199999	29	71	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Franklin County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Franklin County	Missouri	1
MO	2907399999	29	73	NCNTY29073N29073	Gasconade County, MO	Gasconade County	63500	13350	15250	17150	19050	20600	22100	23650	25150	9999	Gasconade County	Missouri	0
MO	2907599999	29	75	NCNTY29075N29075	Gentry County, MO	Gentry County	58500	12300	14050	15800	17550	19000	20400	21800	23200	9999	Gentry County	Missouri	0
MO	2907799999	29	77	METRO44180M44180	Springfield, MO HUD Metro FMR Area	Greene County	65300	13750	15700	17650	19600	21200	22750	24350	25900	7920	Greene County	Missouri	1
MO	2907999999	29	79	NCNTY29079N29079	Grundy County, MO	Grundy County	62500	13150	15000	16900	18750	20250	21750	23250	24750	9999	Grundy County	Missouri	0
MO	2908199999	29	81	NCNTY29081N29081	Harrison County, MO	Harrison County	55800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Harrison County	Missouri	0
MO	2908399999	29	83	NCNTY29083N29083	Henry County, MO	Henry County	57000	12000	13700	15400	17100	18500	19850	21250	22600	9999	Henry County	Missouri	0
MO	2908599999	29	85	NCNTY29085N29085	Hickory County, MO	Hickory County	46000	11800	13500	15200	16850	18200	19550	20900	22250	9999	Hickory County	Missouri	0
MO	2908799999	29	87	NCNTY29087N29087	Holt County, MO	Holt County	59700	12550	14350	16150	17900	19350	20800	22200	23650	9999	Holt County	Missouri	0
MO	2908999999	29	89	NCNTY29089N29089	Howard County, MO	Howard County	65200	13700	15650	17600	19550	21150	22700	24250	25850	9999	Howard County	Missouri	0
MO	2909199999	29	91	NCNTY29091N29091	Howell County, MO	Howell County	46600	11800	13500	15200	16850	18200	19550	20900	22250	9999	Howell County	Missouri	0
MO	2909399999	29	93	NCNTY29093N29093	Iron County, MO	Iron County	48200	11800	13500	15200	16850	18200	19550	20900	22250	9999	Iron County	Missouri	0
MO	2909599999	29	95	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Jackson County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Jackson County	Missouri	1
MO	2909799999	29	97	METRO27900M27900	Joplin, MO MSA	Jasper County	63300	13200	15100	17000	18850	20400	21900	23400	24900	3710	Jasper County	Missouri	1
MO	2909999999	29	99	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Jefferson County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Jefferson County	Missouri	1
MO	2910199999	29	101	NCNTY29101N29101	Johnson County, MO	Johnson County	66800	14050	16050	18050	20050	21700	23300	24900	26500	9999	Johnson County	Missouri	0
MO	2910399999	29	103	NCNTY29103N29103	Knox County, MO	Knox County	53500	11800	13500	15200	16850	18200	19550	20900	22250	9999	Knox County	Missouri	0
MO	2910599999	29	105	NCNTY29105N29105	Laclede County, MO	Laclede County	53900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Laclede County	Missouri	0
MO	2910799999	29	107	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Lafayette County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Lafayette County	Missouri	1
MO	2910999999	29	109	NCNTY29109N29109	Lawrence County, MO	Lawrence County	52800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Lawrence County	Missouri	0
MO	2911199999	29	111	NCNTY29111N29111	Lewis County, MO	Lewis County	61700	12950	14800	16650	18500	20000	21500	22950	24450	9999	Lewis County	Missouri	0
MO	2911399999	29	113	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Lincoln County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Lincoln County	Missouri	1
MO	2911599999	29	115	NCNTY29115N29115	Linn County, MO	Linn County	53100	11800	13500	15200	16850	18200	19550	20900	22250	9999	Linn County	Missouri	0
MO	2911799999	29	117	NCNTY29117N29117	Livingston County, MO	Livingston County	62800	13200	15100	17000	18850	20400	21900	23400	24900	9999	Livingston County	Missouri	0
MO	2911999999	29	119	METRO22220N29119	McDonald County, MO HUD Metro FMR Area	McDonald County	48200	11800	13500	15200	16850	18200	19550	20900	22250	9999	McDonald County	Missouri	1
MO	2912199999	29	121	NCNTY29121N29121	Macon County, MO	Macon County	54700	11800	13500	15200	16850	18200	19550	20900	22250	9999	Macon County	Missouri	0
MO	2912399999	29	123	NCNTY29123N29123	Madison County, MO	Madison County	53900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Madison County	Missouri	0
MO	2912599999	29	125	NCNTY29125N29125	Maries County, MO	Maries County	59000	12400	14200	15950	17700	19150	20550	21950	23400	9999	Maries County	Missouri	0
MO	2912799999	29	127	NCNTY29127N29127	Marion County, MO	Marion County	59600	12550	14350	16150	17900	19350	20800	22200	23650	9999	Marion County	Missouri	0
MO	2912999999	29	129	NCNTY29129N29129	Mercer County, MO	Mercer County	54900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Mercer County	Missouri	0
MO	2913199999	29	131	NCNTY29131N29131	Miller County, MO	Miller County	54600	11800	13500	15200	16850	18200	19550	20900	22250	9999	Miller County	Missouri	0
MO	2913399999	29	133	NCNTY29133N29133	Mississippi County, MO	Mississippi County	37900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Mississippi County	Missouri	0
MO	2913599999	29	135	METRO27620N29135	Moniteau County, MO HUD Metro FMR Area	Moniteau County	64000	13450	15400	17300	19200	20750	22300	23850	25350	9999	Moniteau County	Missouri	1
MO	2913799999	29	137	NCNTY29137N29137	Monroe County, MO	Monroe County	57900	12150	13900	15650	17350	18750	20150	21550	22950	9999	Monroe County	Missouri	0
MO	2913999999	29	139	NCNTY29139N29139	Montgomery County, MO	Montgomery County	55400	11800	13500	15200	16850	18200	19550	20900	22250	9999	Montgomery County	Missouri	0
MO	2914199999	29	141	NCNTY29141N29141	Morgan County, MO	Morgan County	48700	11800	13500	15200	16850	18200	19550	20900	22250	9999	Morgan County	Missouri	0
MO	2914399999	29	143	NCNTY29143N29143	New Madrid County, MO	New Madrid County	44500	11800	13500	15200	16850	18200	19550	20900	22250	9999	New Madrid County	Missouri	0
MO	2914599999	29	145	METRO27900M27900	Joplin, MO MSA	Newton County	63300	13200	15100	17000	18850	20400	21900	23400	24900	3710	Newton County	Missouri	1
MO	2914799999	29	147	NCNTY29147N29147	Nodaway County, MO	Nodaway County	63100	13300	15200	17100	18950	20500	22000	23500	25050	9999	Nodaway County	Missouri	0
MO	2914999999	29	149	NCNTY29149N29149	Oregon County, MO	Oregon County	44200	11800	13500	15200	16850	18200	19550	20900	22250	9999	Oregon County	Missouri	0
MO	2915199999	29	151	METRO27620M27620	Jefferson City, MO HUD Metro FMR Area	Osage County	75500	15900	18150	20400	22650	24500	26300	28100	29900	9999	Osage County	Missouri	1
MO	2915399999	29	153	NCNTY29153N29153	Ozark County, MO	Ozark County	43900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Ozark County	Missouri	0
MO	2915599999	29	155	NCNTY29155N29155	Pemiscot County, MO	Pemiscot County	46700	11800	13500	15200	16850	18200	19550	20900	22250	9999	Pemiscot County	Missouri	0
MO	2915799999	29	157	NCNTY29157N29157	Perry County, MO	Perry County	72000	15150	17300	19450	21600	23350	25100	26800	28550	9999	Perry County	Missouri	0
MO	2915999999	29	159	NCNTY29159N29159	Pettis County, MO	Pettis County	55100	11800	13500	15200	16850	18200	19550	20900	22250	9999	Pettis County	Missouri	0
MO	2916199999	29	161	NCNTY29161N29161	Phelps County, MO	Phelps County	61900	13000	14850	16700	18550	20050	21550	23050	24500	9999	Phelps County	Missouri	0
MO	2916399999	29	163	NCNTY29163N29163	Pike County, MO	Pike County	60200	12650	14450	16250	18050	19500	20950	22400	23850	9999	Pike County	Missouri	0
MO	2916599999	29	165	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Platte County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Platte County	Missouri	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MO	2916799999	29	167	METRO44180N29167	Polk County, MO HUD Metro FMR Area	Polk County	55200	11800	13500	15200	16850	18200	19550	20900	22250	9999	Polk County	Missouri	1
MO	2916999999	29	169	NCNTY29169N29169	Pulaski County, MO	Pulaski County	65400	13600	15550	17500	19400	21000	22550	24100	25650	9999	Pulaski County	Missouri	0
MO	2917199999	29	171	NCNTY29171N29171	Putnam County, MO	Putnam County	47700	11800	13500	15200	16850	18200	19550	20900	22250	9999	Putnam County	Missouri	0
MO	2917399999	29	173	NCNTY29173N29173	Ralls County, MO	Ralls County	64000	13450	15400	17300	19200	20750	22300	23850	25350	9999	Ralls County	Missouri	0
MO	2917599999	29	175	NCNTY29175N29175	Randolph County, MO	Randolph County	63000	13000	14850	16700	18550	20050	21550	23050	24500	9999	Randolph County	Missouri	0
MO	2917799999	29	177	METRO28140M28140	Kansas City, MO-KS HUD Metro FMR Area	Ray County	86000	18100	20650	23250	25800	27900	29950	32000	34100	3760	Ray County	Missouri	1
MO	2917999999	29	179	NCNTY29179N29179	Reynolds County, MO	Reynolds County	53900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Reynolds County	Missouri	0
MO	2918199999	29	181	NCNTY29181N29181	Ripley County, MO	Ripley County	44200	11800	13500	15200	16850	18200	19550	20900	22250	9999	Ripley County	Missouri	0
MO	2918399999	29	183	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	St. Charles County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	St. Charles County	Missouri	1
MO	2918599999	29	185	NCNTY29185N29185	St. Clair County, MO	St. Clair County	48100	11800	13500	15200	16850	18200	19550	20900	22250	9999	St. Clair County	Missouri	0
MO	2918699999	29	186	NCNTY29186N29186	Ste. Genevieve County, MO	Ste. Genevieve County	62700	13200	15050	16950	18800	20350	21850	23350	24850	9999	Ste. Genevieve County	Missouri	0
MO	2918799999	29	187	NCNTY29187N29187	St. Francois County, MO	St. Francois County	60200	12650	14450	16250	18050	19500	20950	22400	23850	9999	St. Francois County	Missouri	0
MO	2918999999	29	189	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	St. Louis County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	St. Louis County	Missouri	1
MO	2919599999	29	195	NCNTY29195N29195	Saline County, MO	Saline County	55600	11800	13500	15200	16850	18200	19550	20900	22250	9999	Saline County	Missouri	0
MO	2919799999	29	197	NCNTY29197N29197	Schuyler County, MO	Schuyler County	51900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Schuyler County	Missouri	0
MO	2919999999	29	199	NCNTY29199N29199	Scotland County, MO	Scotland County	62700	13200	15050	16950	18800	20350	21850	23350	24850	9999	Scotland County	Missouri	0
MO	2920199999	29	201	NCNTY29201N29201	Scott County, MO	Scott County	53400	11800	13500	15200	16850	18200	19550	20900	22250	9999	Scott County	Missouri	0
MO	2920399999	29	203	NCNTY29203N29203	Shannon County, MO	Shannon County	46500	11800	13500	15200	16850	18200	19550	20900	22250	9999	Shannon County	Missouri	0
MO	2920599999	29	205	NCNTY29205N29205	Shelby County, MO	Shelby County	59600	12550	14350	16150	17900	19350	20800	22200	23650	9999	Shelby County	Missouri	0
MO	2920799999	29	207	NCNTY29207N29207	Stoddard County, MO	Stoddard County	52300	11800	13500	15200	16850	18200	19550	20900	22250	9999	Stoddard County	Missouri	0
MO	2920999999	29	209	NCNTY29209N29209	Stone County, MO	Stone County	55800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Stone County	Missouri	0
MO	2921199999	29	211	NCNTY29211N29211	Sullivan County, MO	Sullivan County	54500	11800	13500	15200	16850	18200	19550	20900	22250	9999	Sullivan County	Missouri	0
MO	2921399999	29	213	NCNTY29213N29213	Taney County, MO	Taney County	51800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Taney County	Missouri	0
MO	2921599999	29	215	NCNTY29215N29215	Texas County, MO	Texas County	48800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Texas County	Missouri	0
MO	2921799999	29	217	NCNTY29217N29217	Vernon County, MO	Vernon County	52800	11800	13500	15200	16850	18200	19550	20900	22250	9999	Vernon County	Missouri	0
MO	2921999999	29	219	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	Warren County	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	Warren County	Missouri	1
MO	2922199999	29	221	NCNTY29221N29221	Washington County, MO	Washington County	44600	11800	13500	15200	16850	18200	19550	20900	22250	9999	Washington County	Missouri	0
MO	2922399999	29	223	NCNTY29223N29223	Wayne County, MO	Wayne County	43900	11800	13500	15200	16850	18200	19550	20900	22250	9999	Wayne County	Missouri	0
MO	2922599999	29	225	METRO44180M44180	Springfield, MO HUD Metro FMR Area	Webster County	65300	13750	15700	17650	19600	21200	22750	24350	25900	7920	Webster County	Missouri	1
MO	2922799999	29	227	NCNTY29227N29227	Worth County, MO	Worth County	58000	12200	13950	15700	17400	18800	20200	21600	23000	9999	Worth County	Missouri	0
MO	2922999999	29	229	NCNTY29229N29229	Wright County, MO	Wright County	42600	11800	13500	15200	16850	18200	19550	20900	22250	9999	Wright County	Missouri	0
MO	2951099999	29	510	METRO41180M41180	St. Louis, MO-IL HUD Metro FMR Area	St. Louis city	82900	17400	19900	22400	24850	26850	28850	30850	32850	7040	St. Louis city	Missouri	1
MT	3000199999	30	1	NCNTY30001N30001	Beaverhead County, MT	Beaverhead County	69300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Beaverhead County	Montana	0
MT	3000399999	30	3	NCNTY30003N30003	Big Horn County, MT	Big Horn County	55300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Big Horn County	Montana	0
MT	3000599999	30	5	NCNTY30005N30005	Blaine County, MT	Blaine County	46200	15000	17150	19300	21400	23150	24850	26550	28250	9999	Blaine County	Montana	0
MT	3000799999	30	7	NCNTY30007N30007	Broadwater County, MT	Broadwater County	70800	15000	17150	19300	21400	23150	24850	26550	28250	9999	Broadwater County	Montana	0
MT	3000999999	30	9	METRO13740M13740	Billings, MT HUD Metro FMR Area	Carbon County	76600	16100	18400	20700	23000	24850	26700	28550	30400	9999	Carbon County	Montana	1
MT	3001199999	30	11	NCNTY30011N30011	Carter County, MT	Carter County	65400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Carter County	Montana	0
MT	3001399999	30	13	METRO24500M24500	Great Falls, MT MSA	Cascade County	67400	15000	17150	19300	21400	23150	24850	26550	28250	3040	Cascade County	Montana	1
MT	3001599999	30	15	NCNTY30015N30015	Chouteau County, MT	Chouteau County	53400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Chouteau County	Montana	0
MT	3001799999	30	17	NCNTY30017N30017	Custer County, MT	Custer County	76500	16100	18400	20700	22950	24800	26650	28500	30300	9999	Custer County	Montana	0
MT	3001999999	30	19	NCNTY30019N30019	Daniels County, MT	Daniels County	75800	15950	18200	20500	22750	24600	26400	28250	30050	9999	Daniels County	Montana	0
MT	3002199999	30	21	NCNTY30021N30021	Dawson County, MT	Dawson County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Dawson County	Montana	0
MT	3002399999	30	23	NCNTY30023N30023	Deer Lodge County, MT	Deer Lodge County	60100	15000	17150	19300	21400	23150	24850	26550	28250	9999	Deer Lodge County	Montana	0
MT	3002599999	30	25	NCNTY30025N30025	Fallon County, MT	Fallon County	77100	16250	18550	20850	23150	25050	26900	28750	30600	9999	Fallon County	Montana	0
MT	3002799999	30	27	NCNTY30027N30027	Fergus County, MT	Fergus County	57800	15000	17150	19300	21400	23150	24850	26550	28250	9999	Fergus County	Montana	0
MT	3002999999	30	29	NCNTY30029N30029	Flathead County, MT	Flathead County	73800	15550	17750	19950	22150	23950	25700	27500	29250	9999	Flathead County	Montana	0
MT	3003199999	30	31	NCNTY30031N30031	Gallatin County, MT	Gallatin County	90400	19000	21700	24400	27100	29300	31450	33650	35800	9999	Gallatin County	Montana	0
MT	3003399999	30	33	NCNTY30033N30033	Garfield County, MT	Garfield County	68400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Garfield County	Montana	0
MT	3003599999	30	35	NCNTY30035N30035	Glacier County, MT	Glacier County	46300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Glacier County	Montana	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
MT	3003799999	30	37	METRO13740N30037	Golden Valley County, MT HUD Metro FMR Area	Golden Valley County	76500	16100	18400	20700	22950	24800	26650	28500	30300	9999	Golden Valley County	Montana	1
MT	3003999999	30	39	NCNTY30039N30039	Granite County, MT	Granite County	59400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Granite County	Montana	0
MT	3004199999	30	41	NCNTY30041N30041	Hill County, MT	Hill County	57300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Hill County	Montana	0
MT	3004399999	30	43	NCNTY30043N30043	Jefferson County, MT	Jefferson County	82800	17400	19900	22400	24850	26850	28850	30850	32850	9999	Jefferson County	Montana	0
MT	3004599999	30	45	NCNTY30045N30045	Judith Basin County, MT	Judith Basin County	62200	15000	17150	19300	21400	23150	24850	26550	28250	9999	Judith Basin County	Montana	0
MT	3004799999	30	47	NCNTY30047N30047	Lake County, MT	Lake County	58300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Lake County	Montana	0
MT	3004999999	30	49	NCNTY30049N30049	Lewis and Clark County, MT	Lewis and Clark County	83800	17650	20150	22650	25150	27200	29200	31200	33200	9999	Lewis and Clark County	Montana	0
MT	3005199999	30	51	NCNTY30051N30051	Liberty County, MT	Liberty County	67700	15000	17150	19300	21400	23150	24850	26550	28250	9999	Liberty County	Montana	0
MT	3005399999	30	53	NCNTY30053N30053	Lincoln County, MT	Lincoln County	49900	15000	17150	19300	21400	23150	24850	26550	28250	9999	Lincoln County	Montana	0
MT	3005599999	30	55	NCNTY30055N30055	McCone County, MT	McCone County	69700	15000	17150	19300	21400	23150	24850	26550	28250	9999	McCone County	Montana	0
MT	3005799999	30	57	NCNTY30057N30057	Madison County, MT	Madison County	65000	15000	17150	19300	21400	23150	24850	26550	28250	9999	Madison County	Montana	0
MT	3005999999	30	59	NCNTY30059N30059	Meagher County, MT	Meagher County	49300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Meagher County	Montana	0
MT	3006199999	30	61	NCNTY30061N30061	Mineral County, MT	Mineral County	58400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Mineral County	Montana	0
MT	3006399999	30	63	METRO33540M33540	Missoula, MT MSA	Missoula County	84300	16650	19000	21400	23750	25650	27550	29450	31350	5140	Missoula County	Montana	1
MT	3006599999	30	65	NCNTY30065N30065	Musselshell County, MT	Musselshell County	56100	15000	17150	19300	21400	23150	24850	26550	28250	9999	Musselshell County	Montana	0
MT	3006799999	30	67	NCNTY30067N30067	Park County, MT	Park County	71000	15000	17150	19300	21400	23150	24850	26550	28250	9999	Park County	Montana	0
MT	3006999999	30	69	NCNTY30069N30069	Petroleum County, MT	Petroleum County	62500	15000	17150	19300	21400	23150	24850	26550	28250	9999	Petroleum County	Montana	0
MT	3007199999	30	71	NCNTY30071N30071	Phillips County, MT	Phillips County	58900	15000	17150	19300	21400	23150	24850	26550	28250	9999	Phillips County	Montana	0
MT	3007399999	30	73	NCNTY30073N30073	Pondera County, MT	Pondera County	58400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Pondera County	Montana	0
MT	3007599999	30	75	NCNTY30075N30075	Powder River County, MT	Powder River County	64000	15000	17150	19300	21400	23150	24850	26550	28250	9999	Powder River County	Montana	0
MT	3007799999	30	77	NCNTY30077N30077	Powell County, MT	Powell County	59000	15000	17150	19300	21400	23150	24850	26550	28250	9999	Powell County	Montana	0
MT	3007999999	30	79	NCNTY30079N30079	Prairie County, MT	Prairie County	59000	15000	17150	19300	21400	23150	24850	26550	28250	9999	Prairie County	Montana	0
MT	3008199999	30	81	NCNTY30081N30081	Ravalli County, MT	Ravalli County	62300	15000	17150	19300	21400	23150	24850	26550	28250	9999	Ravalli County	Montana	0
MT	3008399999	30	83	NCNTY30083N30083	Richland County, MT	Richland County	83000	17450	19950	22450	24900	26900	28900	30900	32900	9999	Richland County	Montana	0
MT	3008599999	30	85	NCNTY30085N30085	Roosevelt County, MT	Roosevelt County	55600	15000	17150	19300	21400	23150	24850	26550	28250	9999	Roosevelt County	Montana	0
MT	3008799999	30	87	NCNTY30087N30087	Rosebud County, MT	Rosebud County	75000	15750	18000	20250	22500	24300	26100	27900	29700	9999	Rosebud County	Montana	0
MT	3008999999	30	89	NCNTY30089N30089	Sanders County, MT	Sanders County	48000	15000	17150	19300	21400	23150	24850	26550	28250	9999	Sanders County	Montana	0
MT	3009199999	30	91	NCNTY30091N30091	Sheridan County, MT	Sheridan County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Sheridan County	Montana	0
MT	3009399999	30	93	NCNTY30093N30093	Silver Bow County, MT	Silver Bow County	61700	15000	17150	19300	21400	23150	24850	26550	28250	9999	Silver Bow County	Montana	0
MT	3009599999	30	95	NCNTY30095N30095	Stillwater County, MT	Stillwater County	82500	17350	19800	22300	24750	26750	28750	30700	32700	9999	Stillwater County	Montana	0
MT	3009799999	30	97	NCNTY30097N30097	Sweet Grass County, MT	Sweet Grass County	68600	15000	17150	19300	21400	23150	24850	26550	28250	9999	Sweet Grass County	Montana	0
MT	3009999999	30	99	NCNTY30099N30099	Teton County, MT	Teton County	66200	15000	17150	19300	21400	23150	24850	26550	28250	9999	Teton County	Montana	0
MT	3010199999	30	101	NCNTY30101N30101	Toole County, MT	Toole County	61500	15000	17150	19300	21400	23150	24850	26550	28250	9999	Toole County	Montana	0
MT	3010399999	30	103	NCNTY30103N30103	Treasure County, MT	Treasure County	52200	15000	17150	19300	21400	23150	24850	26550	28250	9999	Treasure County	Montana	0
MT	3010599999	30	105	NCNTY30105N30105	Valley County, MT	Valley County	69400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Valley County	Montana	0
MT	3010799999	30	107	NCNTY30107N30107	Wheatland County, MT	Wheatland County	45500	15000	17150	19300	21400	23150	24850	26550	28250	9999	Wheatland County	Montana	0
MT	3010999999	30	109	NCNTY30109N30109	Wibaux County, MT	Wibaux County	63000	15000	17150	19300	21400	23150	24850	26550	28250	9999	Wibaux County	Montana	0
MT	3011199999	30	111	METRO13740M13740	Billings, MT HUD Metro FMR Area	Yellowstone County	76600	16100	18400	20700	23000	24850	26700	28550	30400	880	Yellowstone County	Montana	1
NE	3100199999	31	1	NCNTY31001N31001	Adams County, NE	Adams County	72900	15300	17500	19700	21850	23600	25350	27100	28850	9999	Adams County	Nebraska	0
NE	3100399999	31	3	NCNTY31003N31003	Antelope County, NE	Antelope County	62700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Antelope County	Nebraska	0
NE	3100599999	31	5	NCNTY31005N31005	Arthur County, NE	Arthur County	65100	15050	17200	19350	21500	23250	24950	26700	28400	9999	Arthur County	Nebraska	0
NE	3100799999	31	7	NCNTY31007N31007	Banner County, NE	Banner County	69900	15050	17200	19350	21500	23250	24950	26700	28400	9999	Banner County	Nebraska	0
NE	3100999999	31	9	NCNTY31009N31009	Blaine County, NE	Blaine County	61700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Blaine County	Nebraska	0
NE	3101199999	31	11	NCNTY31011N31011	Boone County, NE	Boone County	73200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Boone County	Nebraska	0
NE	3101399999	31	13	NCNTY31013N31013	Box Butte County, NE	Box Butte County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Box Butte County	Nebraska	0
NE	3101599999	31	15	NCNTY31015N31015	Boyd County, NE	Boyd County	67700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Boyd County	Nebraska	0
NE	3101799999	31	17	NCNTY31017N31017	Brown County, NE	Brown County	55900	15050	17200	19350	21500	23250	24950	26700	28400	9999	Brown County	Nebraska	0
NE	3101999999	31	19	NCNTY31019N31019	Buffalo County, NE	Buffalo County	77800	16350	18700	21050	23350	25250	27100	29000	30850	9999	Buffalo County	Nebraska	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NE	3102199999	31	21	NCNTY31021N31021	Burt County, NE	Burt County	67000	15050	17200	19350	21500	23250	24950	26700	28400	9999	Burt County	Nebraska	0
NE	3102399999	31	23	NCNTY31023N31023	Butler County, NE	Butler County	69800	15050	17200	19350	21500	23250	24950	26700	28400	9999	Butler County	Nebraska	0
NE	3102599999	31	25	METRO36540M36540	Omaha-Council Bluffs, NE-IA HUD Metro FMR Area	Cass County	87000	18300	20900	23500	26100	28200	30300	32400	34500	5920	Cass County	Nebraska	1
NE	3102799999	31	27	NCNTY31027N31027	Cedar County, NE	Cedar County	75600	15900	18200	20450	22700	24550	26350	28150	30000	9999	Cedar County	Nebraska	0
NE	3102999999	31	29	NCNTY31029N31029	Chase County, NE	Chase County	66000	15050	17200	19350	21500	23250	24950	26700	28400	9999	Chase County	Nebraska	0
NE	3103199999	31	31	NCNTY31031N31031	Cherry County, NE	Cherry County	65500	15050	17200	19350	21500	23250	24950	26700	28400	9999	Cherry County	Nebraska	0
NE	3103399999	31	33	NCNTY31033N31033	Cheyenne County, NE	Cheyenne County	82200	17300	19750	22200	24650	26650	28600	30600	32550	9999	Cheyenne County	Nebraska	0
NE	3103599999	31	35	NCNTY31035N31035	Clay County, NE	Clay County	68400	15050	17200	19350	21500	23250	24950	26700	28400	9999	Clay County	Nebraska	0
NE	3103799999	31	37	NCNTY31037N31037	Colfax County, NE	Colfax County	66800	15050	17200	19350	21500	23250	24950	26700	28400	9999	Colfax County	Nebraska	0
NE	3103999999	31	39	NCNTY31039N31039	Cuming County, NE	Cuming County	68400	15050	17200	19350	21500	23250	24950	26700	28400	9999	Cuming County	Nebraska	0
NE	3104199999	31	41	NCNTY31041N31041	Custer County, NE	Custer County	64000	15050	17200	19350	21500	23250	24950	26700	28400	9999	Custer County	Nebraska	0
NE	3104399999	31	43	METRO43580M43580	Sioux City, IA-NE-SD HUD Metro FMR Area	Dakota County	75200	15750	18000	20250	22500	24300	26100	27900	29700	7720	Dakota County	Nebraska	1
NE	3104599999	31	45	NCNTY31045N31045	Dawes County, NE	Dawes County	67200	15050	17200	19350	21500	23250	24950	26700	28400	9999	Dawes County	Nebraska	0
NE	3104799999	31	47	NCNTY31047N31047	Dawson County, NE	Dawson County	63100	15050	17200	19350	21500	23250	24950	26700	28400	9999	Dawson County	Nebraska	0
NE	3104999999	31	49	NCNTY31049N31049	Deuel County, NE	Deuel County	63300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Deuel County	Nebraska	0
NE	3105199999	31	51	METRO43580M43580	Sioux City, IA-NE-SD HUD Metro FMR Area	Dixon County	75200	15750	18000	20250	22500	24300	26100	27900	29700	9999	Dixon County	Nebraska	1
NE	3105399999	31	53	NCNTY31053N31053	Dodge County, NE	Dodge County	64700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Dodge County	Nebraska	0
NE	3105599999	31	55	METRO36540M36540	Omaha-Council Bluffs, NE-IA HUD Metro FMR Area	Douglas County	87000	18300	20900	23500	26100	28200	30300	32400	34500	5920	Douglas County	Nebraska	1
NE	3105799999	31	57	NCNTY31057N31057	Dundy County, NE	Dundy County	60200	15050	17200	19350	21500	23250	24950	26700	28400	9999	Dundy County	Nebraska	0
NE	3105999999	31	59	NCNTY31059N31059	Fillmore County, NE	Fillmore County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Fillmore County	Nebraska	0
NE	3106199999	31	61	NCNTY31061N31061	Franklin County, NE	Franklin County	64800	15050	17200	19350	21500	23250	24950	26700	28400	9999	Franklin County	Nebraska	0
NE	3106399999	31	63	NCNTY31063N31063	Frontier County, NE	Frontier County	65500	15050	17200	19350	21500	23250	24950	26700	28400	9999	Frontier County	Nebraska	0
NE	3106599999	31	65	NCNTY31065N31065	Furnas County, NE	Furnas County	64900	15050	17200	19350	21500	23250	24950	26700	28400	9999	Furnas County	Nebraska	0
NE	3106799999	31	67	NCNTY31067N31067	Gage County, NE	Gage County	71200	15050	17200	19350	21500	23250	24950	26700	28400	9999	Gage County	Nebraska	0
NE	3106999999	31	69	NCNTY31069N31069	Garden County, NE	Garden County	72200	15200	17350	19500	21650	23400	25150	26850	28600	9999	Garden County	Nebraska	0
NE	3107199999	31	71	NCNTY31071N31071	Garfield County, NE	Garfield County	58800	15050	17200	19350	21500	23250	24950	26700	28400	9999	Garfield County	Nebraska	0
NE	3107399999	31	73	NCNTY31073N31073	Gosper County, NE	Gosper County	84800	16950	19400	21800	24200	26150	28100	30050	31950	9999	Gosper County	Nebraska	0
NE	3107599999	31	75	NCNTY31075N31075	Grant County, NE	Grant County	57900	15050	17200	19350	21500	23250	24950	26700	28400	9999	Grant County	Nebraska	0
NE	3107799999	31	77	NCNTY31077N31077	Greeley County, NE	Greeley County	63600	15050	17200	19350	21500	23250	24950	26700	28400	9999	Greeley County	Nebraska	0
NE	3107999999	31	79	METRO24260N31079	Hall County, NE HUD Metro FMR Area	Hall County	66300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Hall County	Nebraska	1
NE	3108199999	31	81	METRO24260N31081	Hamilton County, NE HUD Metro FMR Area	Hamilton County	80200	16850	19250	21650	24050	26000	27900	29850	31750	9999	Hamilton County	Nebraska	1
NE	3108399999	31	83	NCNTY31083N31083	Harlan County, NE	Harlan County	66900	15050	17200	19350	21500	23250	24950	26700	28400	9999	Harlan County	Nebraska	0
NE	3108599999	31	85	NCNTY31085N31085	Hayes County, NE	Hayes County	67100	15050	17200	19350	21500	23250	24950	26700	28400	9999	Hayes County	Nebraska	0
NE	3108799999	31	87	NCNTY31087N31087	Hitchcock County, NE	Hitchcock County	58200	15050	17200	19350	21500	23250	24950	26700	28400	9999	Hitchcock County	Nebraska	0
NE	3108999999	31	89	NCNTY31089N31089	Holt County, NE	Holt County	67900	15050	17200	19350	21500	23250	24950	26700	28400	9999	Holt County	Nebraska	0
NE	3109199999	31	91	NCNTY31091N31091	Hooker County, NE	Hooker County	56500	15050	17200	19350	21500	23250	24950	26700	28400	9999	Hooker County	Nebraska	0
NE	3109399999	31	93	METRO24260N31093	Howard County, NE HUD Metro FMR Area	Howard County	72700	15300	17450	19650	21800	23550	25300	27050	28800	9999	Howard County	Nebraska	1
NE	3109599999	31	95	NCNTY31095N31095	Jefferson County, NE	Jefferson County	58300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Jefferson County	Nebraska	0
NE	3109799999	31	97	NCNTY31097N31097	Johnson County, NE	Johnson County	64100	15050	17200	19350	21500	23250	24950	26700	28400	9999	Johnson County	Nebraska	0
NE	3109999999	31	99	NCNTY31099N31099	Kearney County, NE	Kearney County	75900	15950	18200	20500	22750	24600	26400	28250	30050	9999	Kearney County	Nebraska	0
NE	3110199999	31	101	NCNTY31101N31101	Keith County, NE	Keith County	61500	15050	17200	19350	21500	23250	24950	26700	28400	9999	Keith County	Nebraska	0
NE	3110399999	31	103	NCNTY31103N31103	Keya Paha County, NE	Keya Paha County	56300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Keya Paha County	Nebraska	0
NE	3110599999	31	105	NCNTY31105N31105	Kimball County, NE	Kimball County	56600	15050	17200	19350	21500	23250	24950	26700	28400	9999	Kimball County	Nebraska	0
NE	3110799999	31	107	NCNTY31107N31107	Knox County, NE	Knox County	65100	15050	17200	19350	21500	23250	24950	26700	28400	9999	Knox County	Nebraska	0
NE	3110999999	31	109	METRO30700M30700	Lincoln, NE HUD Metro FMR Area	Lancaster County	82100	17300	19750	22200	24650	26650	28600	30600	32550	4360	Lancaster County	Nebraska	1

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NE	3111199999	31	111	NCNTY31111N31111	Lincoln County, NE	Lincoln County	73500	15450	17650	19850	22050	23850	25600	27350	29150	9999	Lincoln County	Nebraska	0
NE	3111399999	31	113	NCNTY31113N31113	Logan County, NE	Logan County	69100	15050	17200	19350	21500	23250	24950	26700	28400	9999	Logan County	Nebraska	0
NE	3111599999	31	115	NCNTY31115N31115	Loup County, NE	Loup County	68400	15050	17200	19350	21500	23250	24950	26700	28400	9999	Loup County	Nebraska	0
NE	3111799999	31	117	NCNTY31117N31117	McPherson County, NE	McPherson County	74300	15650	17850	20100	22300	24100	25900	27700	29450	9999	McPherson County	Nebraska	0
NE	3111999999	31	119	NCNTY31119N31119	Madison County, NE	Madison County	67600	15050	17200	19350	21500	23250	24950	26700	28400	9999	Madison County	Nebraska	0
NE	3112199999	31	121	METRO24260N31121	Merrick County, NE HUD Metro FMR Area	Merrick County	69700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Merrick County	Nebraska	1
NE	3112399999	31	123	NCNTY31123N31123	Morrill County, NE	Morrill County	58800	15050	17200	19350	21500	23250	24950	26700	28400	9999	Morrill County	Nebraska	0
NE	3112599999	31	125	NCNTY31125N31125	Nance County, NE	Nance County	65300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Nance County	Nebraska	0
NE	3112799999	31	127	NCNTY31127N31127	Nemaha County, NE	Nemaha County	73700	15850	18100	20350	22600	24450	26250	28050	29850	9999	Nemaha County	Nebraska	0
NE	3112999999	31	129	NCNTY31129N31129	Nuckolls County, NE	Nuckolls County	58200	15050	17200	19350	21500	23250	24950	26700	28400	9999	Nuckolls County	Nebraska	0
NE	3113199999	31	131	NCNTY31131N31131	Otoe County, NE	Otoe County	73300	15400	17600	19800	22000	23800	25550	27300	29050	9999	Otoe County	Nebraska	0
NE	3113399999	31	133	NCNTY31133N31133	Pawnee County, NE	Pawnee County	59900	15050	17200	19350	21500	23250	24950	26700	28400	9999	Pawnee County	Nebraska	0
NE	3113599999	31	135	NCNTY31135N31135	Perkins County, NE	Perkins County	73900	15550	17750	19950	22150	23950	25700	27500	29250	9999	Perkins County	Nebraska	0
NE	3113799999	31	137	NCNTY31137N31137	Phelps County, NE	Phelps County	76800	16150	18450	20750	23050	24900	26750	28600	30450	9999	Phelps County	Nebraska	0
NE	3113999999	31	139	NCNTY31139N31139	Pierce County, NE	Pierce County	74200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Pierce County	Nebraska	0
NE	3114199999	31	141	NCNTY31141N31141	Platte County, NE	Platte County	78000	16400	18750	21100	23400	25300	27150	29050	30900	9999	Platte County	Nebraska	0
NE	3114399999	31	143	NCNTY31143N31143	Polk County, NE	Polk County	81600	17150	19600	22050	24500	26500	28450	30400	32350	9999	Polk County	Nebraska	0
NE	3114599999	31	145	NCNTY31145N31145	Red Willow County, NE	Red Willow County	64000	15050	17200	19350	21500	23250	24950	26700	28400	9999	Red Willow County	Nebraska	0
NE	3114799999	31	147	NCNTY31147N31147	Richardson County, NE	Richardson County	62500	15050	17200	19350	21500	23250	24950	26700	28400	9999	Richardson County	Nebraska	0
NE	3114999999	31	149	NCNTY31149N31149	Rock County, NE	Rock County	69300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Rock County	Nebraska	0
NE	3115199999	31	151	NCNTY31151N31151	Saline County, NE	Saline County	66000	15050	17200	19350	21500	23250	24950	26700	28400	9999	Saline County	Nebraska	0
NE	3115399999	31	153	METRO36540M36540	Omaha-Council Bluffs, NE-IA HUD Metro FMR Area	Sarpy County	87000	18300	20900	23500	26100	28200	30300	32400	34500	5920	Sarpy County	Nebraska	1
NE	3115599999	31	155	METRO36540N31155	Saunders County, NE HUD Metro FMR Area	Saunders County	82800	17400	19900	22400	24850	26850	28850	30850	32850	9999	Saunders County	Nebraska	1
NE	3115799999	31	157	NCNTY31157N31157	Scotts Bluff County, NE	Scotts Bluff County	62400	15050	17200	19350	21500	23250	24950	26700	28400	9999	Scotts Bluff County	Nebraska	0
NE	3115999999	31	159	METRO30700N31159	Seward County, NE HUD Metro FMR Area	Seward County	84600	17800	20350	22900	25400	27450	29500	31500	33550	9999	Seward County	Nebraska	1
NE	3116199999	31	161	NCNTY31161N31161	Sheridan County, NE	Sheridan County	58300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Sheridan County	Nebraska	0
NE	3116399999	31	163	NCNTY31163N31163	Sherman County, NE	Sherman County	69100	15050	17200	19350	21500	23250	24950	26700	28400	9999	Sherman County	Nebraska	0
NE	3116599999	31	165	NCNTY31165N31165	Sioux County, NE	Sioux County	62700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Sioux County	Nebraska	0
NE	3116799999	31	167	NCNTY31167N31167	Stanton County, NE	Stanton County	73500	15450	17650	19850	22050	23850	25600	27350	29150	9999	Stanton County	Nebraska	0
NE	3116999999	31	169	NCNTY31169N31169	Thayer County, NE	Thayer County	69500	15050	17200	19350	21500	23250	24950	26700	28400	9999	Thayer County	Nebraska	0
NE	3117199999	31	171	NCNTY31171N31171	Thomas County, NE	Thomas County	75700	15900	18200	20450	22700	24550	26350	28150	30000	9999	Thomas County	Nebraska	0
NE	3117399999	31	173	NCNTY31173N31173	Thurston County, NE	Thurston County	53000	15050	17200	19350	21500	23250	24950	26700	28400	9999	Thurston County	Nebraska	0
NE	3117599999	31	175	NCNTY31175N31175	Valley County, NE	Valley County	69000	15050	17200	19350	21500	23250	24950	26700	28400	9999	Valley County	Nebraska	0
NE	3117799999	31	177	METRO36540M36540	Omaha-Council Bluffs, NE-IA HUD Metro FMR Area	Washington County	87000	18300	20900	23500	26100	28200	30300	32400	34500	5920	Washington County	Nebraska	1
NE	3117999999	31	179	NCNTY31179N31179	Wayne County, NE	Wayne County	75800	15950	18200	20500	22750	24600	26400	28250	30050	9999	Wayne County	Nebraska	0
NE	3118199999	31	181	NCNTY31181N31181	Webster County, NE	Webster County	63200	15050	17200	19350	21500	23250	24950	26700	28400	9999	Webster County	Nebraska	0
NE	3118399999	31	183	NCNTY31183N31183	Wheeler County, NE	Wheeler County	64400	15050	17200	19350	21500	23250	24950	26700	28400	9999	Wheeler County	Nebraska	0
NE	3118599999	31	185	NCNTY31185N31185	York County, NE	York County	75200	15800	18050	20300	22550	24400	26200	28000	29800	9999	York County	Nebraska	0
NV	3200199999	32	1	NCNTY32001N32001	Churchill County, NV	Churchill County	63300	15750	18000	20250	22500	24300	26100	27900	29700	9999	Churchill County	Nevada	0
NV	3200399999	32	3	METRO29820M29820	Las Vegas-Henderson-Paradise, NV MSA	Clark County	70800	15750	18000	20250	22500	24300	26100	27900	29700	4120	Clark County	Nevada	1
NV	3200599999	32	5	NCNTY32005N32005	Douglas County, NV	Douglas County	75400	15850	18100	20350	22600	24450	26250	28050	29850	9999	Douglas County	Nevada	0
NV	3200799999	32	7	NCNTY32007N32007	Elko County, NV	Elko County	91800	19300	22050	24800	27550	29800	32000	34200	36400	9999	Elko County	Nevada	0
NV	3200999999	32	9	NCNTY32009N32009	Esmeralda County, NV	Esmeralda County	52500	15750	18000	20250	22500	24300	26100	27900	29700	9999	Esmeralda County	Nevada	0
NV	3201199999	32	11	NCNTY32011N32011	Eureka County, NV	Eureka County	118600	21850	25000	28100	31200	33700	36200	38700	41200	9999	Eureka County	Nevada	0
NV	3201399999	32	13	NCNTY32013N32013	Humboldt County, NV	Humboldt County	85900	17900	20450	23000	25550	27600	29650	31700	33750	9999	Humboldt County	Nevada	0
NV	3201599999	32	15	NCNTY32015N32015	Lander County, NV	Lander County	97000	20400	23300	26200	29100	31450	33800	36100	38450	9999	Lander County	Nevada	0
NV	3201799999	32	17	NCNTY32017N32017	Lincoln County, NV	Lincoln County	63300	15750	18000	20250	22500	24300	26100	27900	29700	9999	Lincoln County	Nevada	0
NV	3201999999	32	19	NCNTY32019N32019	Lyon County, NV	Lyon County	64100	15750	18000	20250	22500	24300	26100	27900	29700	9999	Lyon County	Nevada	0

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NV	3202199999	32	21	NCNTY32021N32021	Mineral County, NV	Mineral County	61900	15750	18000	20250	22500	24300	26100	27900	29700	9999	Mineral County	Nevada	0
NV	3202399999	32	23	NCNTY32023N32023	Nye County, NV	Nye County	57300	15750	18000	20250	22500	24300	26100	27900	29700	4120	Nye County	Nevada	0
NV	3202799999	32	27	NCNTY32027N32027	Pershing County, NV	Pershing County	64100	15750	18000	20250	22500	24300	26100	27900	29700	9999	Pershing County	Nevada	0
NV	3202999999	32	29	METRO39900M39900	Reno, NV MSA	Storey County	79600	16750	19150	21550	23900	25850	27750	29650	31550	9999	Storey County	Nevada	1
NV	3203199999	32	31	METRO39900M39900	Reno, NV MSA	Washoe County	79600	16750	19150	21550	23900	25850	27750	29650	31550	6720	Washoe County	Nevada	1
NV	3203399999	32	33	NCNTY32033N32033	White Pine County, NV	White Pine County	73800	15750	18000	20250	22500	24300	26100	27900	29700	9999	White Pine County	Nevada	0
NV	3251099999	32	510	METRO16180M16180	Carson City, NV MSA	Carson City	75400	15800	18050	20300	22550	24400	26200	28000	29800	9999	Carson City	Nevada	1
NH	3300101060	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Alton town	New Hampshire	0
NH	3300103220	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Barnstead town	New Hampshire	0
NH	3300104740	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Belmont town	New Hampshire	0
NH	3300110660	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Center Harbor town	New Hampshire	0
NH	3300128740	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Gilford town	New Hampshire	0
NH	3300128980	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Gilmanton town	New Hampshire	0
NH	3300140180	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Laconia city	New Hampshire	0
NH	3300147140	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Meredith town	New Hampshire	0
NH	3300151540	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	New Hampton town	New Hampshire	0
NH	3300167300	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Sanbornton town	New Hampshire	0
NH	3300177060	33	1	NCNTY33001N33001	Belknap County, NH	Belknap County	82400	17950	20500	23050	25600	27650	29700	31750	33800	9999	Tilton town	New Hampshire	0
NH	3300300420	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Albany town	New Hampshire	0
NH	3300303700	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Bartlett town	New Hampshire	0
NH	3300307940	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Brookfield town	New Hampshire	0
NH	3300311780	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Chatham town	New Hampshire	0
NH	3300314660	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Conway town	New Hampshire	0
NH	3300323380	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Eaton town	New Hampshire	0
NH	3300323620	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Effingham town	New Hampshire	0
NH	3300327700	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Freedom town	New Hampshire	0
NH	3300332500	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Hale's location	New Hampshire	0
NH	3300334500	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Hart's Location town	New Hampshire	0
NH	3300338260	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Jackson town	New Hampshire	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3300345060	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Madison town	New Hampshire	0
NH	3300349380	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Moultonborough town	New Hampshire	0
NH	3300358740	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Ossipee town	New Hampshire	0
NH	3300367780	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Sandwich town	New Hampshire	0
NH	3300376100	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Tamworth town	New Hampshire	0
NH	3300377620	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Tuftonboro town	New Hampshire	0
NH	3300378180	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Wakefield town	New Hampshire	0
NH	3300386420	33	3	NCNTY33003N33003	Carroll County, NH	Carroll County	71900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Wolfeboro town	New Hampshire	0
NH	3300500820	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Alstead town	New Hampshire	0
NH	3300512260	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Chesterfield town	New Hampshire	0
NH	3300519140	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Dublin town	New Hampshire	0
NH	3300526500	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Fitzwilliam town	New Hampshire	0
NH	3300529220	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Gilsum town	New Hampshire	0
NH	3300534420	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Harrisville town	New Hampshire	0
NH	3300536660	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Hinsdale town	New Hampshire	0
NH	3300538500	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Jaffrey town	New Hampshire	0
NH	3300539300	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Keene city	New Hampshire	0
NH	3300545460	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Marlborough town	New Hampshire	0
NH	3300545700	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Marlow town	New Hampshire	0
NH	3300550580	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Nelson town	New Hampshire	0
NH	3300564420	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Richmond town	New Hampshire	0
NH	3300564580	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Rindge town	New Hampshire	0
NH	3300565700	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Roxbury town	New Hampshire	0
NH	3300573700	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Stoddard town	New Hampshire	0
NH	3300574900	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Sullivan town	New Hampshire	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3300575300	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Surry town	New Hampshire	0
NH	3300575700	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Swanzey town	New Hampshire	0
NH	3300577380	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Troy town	New Hampshire	0
NH	3300578420	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Walpole town	New Hampshire	0
NH	3300582660	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Westmoreland town	New Hampshire	0
NH	3300585540	33	5	NCNTY33005N33005	Cheshire County, NH	Cheshire County	86500	18200	20800	23400	25950	28050	30150	32200	34300	9999	Winchester town	New Hampshire	0
NH	3300702420	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Atkinson and Gilmanton Academy grant	New Hampshire	0
NH	3300704100	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Beans grant	New Hampshire	0
NH	3300704260	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Beans purchase	New Hampshire	0
NH	3300705140	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Berlin city	New Hampshire	0
NH	3300708420	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Cambridge township	New Hampshire	0
NH	3300710100	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Carroll town	New Hampshire	0
NH	3300711220	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Chandlers purchase	New Hampshire	0
NH	3300713220	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Clarksville town	New Hampshire	0
NH	3300713780	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Colebrook town	New Hampshire	0
NH	3300713940	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Columbia town	New Hampshire	0
NH	3300716100	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Crawfords purchase	New Hampshire	0
NH	3300716660	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Cutts grant	New Hampshire	0
NH	3300716820	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Dalton town	New Hampshire	0
NH	3300718340	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Dixs grant	New Hampshire	0
NH	3300718420	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Dixville township	New Hampshire	0
NH	3300719300	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Dummer town	New Hampshire	0
NH	3300725140	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Errol town	New Hampshire	0
NH	3300725180	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Ervings location	New Hampshire	0
NH	3300730260	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Gorham town	New Hampshire	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3300731780	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Greens grant	New Hampshire	0
NH	3300732420	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Hadleys purchase	New Hampshire	0
NH	3300738820	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Jefferson town	New Hampshire	0
NH	3300739940	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Kilkenny township	New Hampshire	0
NH	3300740420	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Lancaster town	New Hampshire	0
NH	3300743620	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Low and Burbanks grant	New Hampshire	0
NH	3300746020	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Martins location	New Hampshire	0
NH	3300747860	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Milan town	New Hampshire	0
NH	3300748260	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Millsfield township	New Hampshire	0
NH	3300756100	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Northumberland town	New Hampshire	0
NH	3300757860	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Odell township	New Hampshire	0
NH	3300761620	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Pinkhams grant	New Hampshire	0
NH	3300761780	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Pittsburg town	New Hampshire	0
NH	3300763860	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Randolph town	New Hampshire	0
NH	3300767860	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Sargents purchase	New Hampshire	0
NH	3300768500	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Second College grant	New Hampshire	0
NH	3300768980	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Shelburne town	New Hampshire	0
NH	3300773060	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Stark town	New Hampshire	0
NH	3300773380	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Stewartstown town	New Hampshire	0
NH	3300774180	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Stratford town	New Hampshire	0
NH	3300774500	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Success township	New Hampshire	0
NH	3300776580	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Thompson and Meserves purchase	New Hampshire	0
NH	3300780740	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Wentworth location	New Hampshire	0
NH	3300784420	33	7	NCNTY33007N33007	Coos County, NH	Coos County	61900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Whitefield town	New Hampshire	0
NH	3300900580	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Alexandria town	New Hampshire	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3300902020	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Ashland town	New Hampshire	0
NH	3300903940	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Bath town	New Hampshire	0
NH	3300905060	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Benton town	New Hampshire	0
NH	3300905460	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Bethlehem town	New Hampshire	0
NH	3300907540	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Bridgewater town	New Hampshire	0
NH	3300907700	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Bristol town	New Hampshire	0
NH	3300908660	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Campton town	New Hampshire	0
NH	3300908980	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Canaan town	New Hampshire	0
NH	3300918740	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Dorchester town	New Hampshire	0
NH	3300922020	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Easton town	New Hampshire	0
NH	3300923860	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Ellsworth town	New Hampshire	0
NH	3300924340	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Enfield town	New Hampshire	0
NH	3300927300	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Franconia town	New Hampshire	0
NH	3300930820	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Grafton town	New Hampshire	0
NH	3300932180	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Groton town	New Hampshire	0
NH	3300933860	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Hanover town	New Hampshire	0
NH	3300934820	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Haverhill town	New Hampshire	0
NH	3300935220	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Hebron town	New Hampshire	0
NH	3300936900	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Holderness town	New Hampshire	0
NH	3300940660	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Landaff town	New Hampshire	0
NH	3300941300	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Lebanon city	New Hampshire	0
NH	3300941860	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Lincoln town	New Hampshire	0
NH	3300942020	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Lisbon town	New Hampshire	0
NH	3300942580	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Littleton town	New Hampshire	0
NH	3300942820	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Livermore town	New Hampshire	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3300944100	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Lyman town	New Hampshire	0
NH	3300944260	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Lyme town	New Hampshire	0
NH	3300948980	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Monroe town	New Hampshire	0
NH	3300958340	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Orange town	New Hampshire	0
NH	3300958500	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Orford town	New Hampshire	0
NH	3300961060	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Piermont town	New Hampshire	0
NH	3300962660	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Plymouth town	New Hampshire	0
NH	3300965940	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Rumney town	New Hampshire	0
NH	3300974740	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Sugar Hill town	New Hampshire	0
NH	3300976740	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Thornton town	New Hampshire	0
NH	3300978740	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Warren town	New Hampshire	0
NH	3300979380	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Waterville Valley town	New Hampshire	0
NH	3300980500	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Wentworth town	New Hampshire	0
NH	3300987060	33	9	NCNTY33009N33009	Grafton County, NH	Grafton County	92600	19500	22250	25050	27800	30050	32250	34500	36700	9999	Woodstock town	New Hampshire	0
NH	3301101300	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Amherst town	New Hampshire	1
NH	3301101700	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Antrim town	New Hampshire	1
NH	3301104500	33	11	METRO31700MM4760	Manchester, NH HUD Metro FMR Area	Hillsborough County	83600	17950	20500	23050	25600	27650	29700	31750	33800	4760	Bedford town	New Hampshire	1
NH	3301104900	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Bennington town	New Hampshire	1
NH	3301108100	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Brookline town	New Hampshire	1
NH	3301117780	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Deering town	New Hampshire	1
NH	3301127140	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Francestown town	New Hampshire	1
NH	3301129860	33	11	METRO31700MM4760	Manchester, NH HUD Metro FMR Area	Hillsborough County	83600	17950	20500	23050	25600	27650	29700	31750	33800	4760	Goffstown town	New Hampshire	1
NH	3301131540	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Greenfield town	New Hampshire	1
NH	3301131940	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Greenville town	New Hampshire	1
NH	3301133700	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Hancock town	New Hampshire	1

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NH	3301136180	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Hillsborough town	New Hampshire	1
NH	3301137140	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Hollis town	New Hampshire	1
NH	3301137940	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Hudson town	New Hampshire	1
NH	3301142260	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Litchfield town	New Hampshire	1
NH	3301144580	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Lyndeborough town	New Hampshire	1
NH	3301145140	33	11	METRO31700MM4760	Manchester, NH HUD Metro FMR Area	Hillsborough County	83600	17950	20500	23050	25600	27650	29700	31750	33800	4760	Manchester city	New Hampshire	1
NH	3301146260	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Mason town	New Hampshire	1
NH	3301147540	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Merrimack town	New Hampshire	1
NH	3301148020	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Milford town	New Hampshire	1
NH	3301149140	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Mont Vernon town	New Hampshire	1
NH	3301150260	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Nashua city	New Hampshire	1
NH	3301150740	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	New Boston town	New Hampshire	1
NH	3301151940	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	New Ipswich town	New Hampshire	1
NH	3301159940	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	4560	Pelham town	New Hampshire	1
NH	3301160580	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Peterborough town	New Hampshire	1
NH	3301168820	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Sharon town	New Hampshire	1
NH	3301176260	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Temple town	New Hampshire	1
NH	3301179780	33	11	METRO31700MM4760	Manchester, NH HUD Metro FMR Area	Hillsborough County	83600	17950	20500	23050	25600	27650	29700	31750	33800	4760	Weare town	New Hampshire	1
NH	3301185220	33	11	METRO31700MM5350	Nashua, NH HUD Metro FMR Area	Hillsborough County	113600	23350	26650	30000	33300	36000	38650	41300	44000	5350	Wilton town	New Hampshire	1
NH	3301185940	33	11	METRO31700N33011	Hillsborough County, NH (part) HUD Metro FMR Area	Hillsborough County	94100	19800	22600	25450	28250	30550	32800	35050	37300	9999	Windsor town	New Hampshire	1
NH	3301300660	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	4760	Allenstown town	New Hampshire	0
NH	3301301460	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Andover town	New Hampshire	0
NH	3301306260	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Boscawen town	New Hampshire	0
NH	3301306500	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Bow town	New Hampshire	0
NH	3301306980	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Bradford town	New Hampshire	0

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NH	3301309860	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Canterbury town	New Hampshire	0
NH	3301312420	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Chichester town	New Hampshire	0
NH	3301314200	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Concord city	New Hampshire	0
NH	3301316980	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Danbury town	New Hampshire	0
NH	3301319460	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Dunbarton town	New Hampshire	0
NH	3301324900	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Epsom town	New Hampshire	0
NH	3301327380	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Franklin city	New Hampshire	0
NH	3301335540	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Henniker town	New Hampshire	0
NH	3301335860	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Hill town	New Hampshire	0
NH	3301337300	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	4760	Hooksett town	New Hampshire	0
NH	3301337540	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Hopkinton town	New Hampshire	0
NH	3301343380	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Loudon town	New Hampshire	0
NH	3301350900	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Newbury town	New Hampshire	0
NH	3301352100	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	New London town	New Hampshire	0
NH	3301354260	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Northfield town	New Hampshire	0
NH	3301360020	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Pembroke town	New Hampshire	0
NH	3301361940	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Pittsfield town	New Hampshire	0
NH	3301366980	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Salisbury town	New Hampshire	0
NH	3301375460	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Sutton town	New Hampshire	0
NH	3301378580	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Warner town	New Hampshire	0
NH	3301380020	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Webster town	New Hampshire	0
NH	3301384900	33	13	NCNTY33013N33013	Merrimack County, NH	Merrimack County	89200	18750	21400	24100	26750	28900	31050	33200	35350	9999	Wilmot town	New Hampshire	0
NH	3301502340	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Atkinson town	New Hampshire	1
NH	3301502820	33	15	METRO14460MM4760	Western Rockingham County, NH HUD Metro FMR Area	Rockingham County	112200	23600	26950	30300	33650	36350	39050	41750	44450	4760	Auburn town	New Hampshire	1
NH	3301507220	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Brentwood town	New Hampshire	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3301509300	33	15	METRO14460MM4760	Western Rockingham County, NH HUD Metro FMR Area	Rockingham County	112200	23600	26950	30300	33650	36350	39050	41750	44450	4760	Candia town	New Hampshire	1
NH	3301512100	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Chester town	New Hampshire	1
NH	3301517140	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Danville town	New Hampshire	1
NH	3301517460	33	15	METRO14460MM4760	Western Rockingham County, NH HUD Metro FMR Area	Rockingham County	112200	23600	26950	30300	33650	36350	39050	41750	44450	9999	Deerfield town	New Hampshire	1
NH	3301517940	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Derry town	New Hampshire	1
NH	3301521380	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	East Kingston town	New Hampshire	1
NH	3301524660	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Epping town	New Hampshire	1
NH	3301525380	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Exeter town	New Hampshire	1
NH	3301527940	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Fremont town	New Hampshire	1
NH	3301531700	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Greenland town	New Hampshire	1
NH	3301532900	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Hampstead town	New Hampshire	1
NH	3301533060	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Hampton town	New Hampshire	1
NH	3301533460	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Hampton Falls town	New Hampshire	1
NH	3301539780	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Kensington town	New Hampshire	1
NH	3301540100	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Kingston town	New Hampshire	1
NH	3301543220	33	15	METRO14460MM4760	Western Rockingham County, NH HUD Metro FMR Area	Rockingham County	112200	23600	26950	30300	33650	36350	39050	41750	44450	4760	Londonderry town	New Hampshire	1
NH	3301550980	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	New Castle town	New Hampshire	1
NH	3301551380	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Newfields town	New Hampshire	1
NH	3301551620	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Newington town	New Hampshire	1
NH	3301552340	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Newmarket town	New Hampshire	1
NH	3301552900	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Newton town	New Hampshire	1
NH	3301554580	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	North Hampton town	New Hampshire	1
NH	3301556820	33	15	METRO14460MM4760	Western Rockingham County, NH HUD Metro FMR Area	Rockingham County	112200	23600	26950	30300	33650	36350	39050	41750	44450	9999	Northwood town	New Hampshire	1
NH	3301557460	33	15	METRO14460MM4760	Western Rockingham County, NH HUD Metro FMR Area	Rockingham County	112200	23600	26950	30300	33650	36350	39050	41750	44450	9999	Nottingham town	New Hampshire	1
NH	3301562500	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Plaistow town	New Hampshire	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3301562900	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Portsmouth city	New Hampshire	1
NH	3301564020	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Raymond town	New Hampshire	1
NH	3301566180	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Rye town	New Hampshire	1
NH	3301566660	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Salem town	New Hampshire	1
NH	3301567620	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Sandown town	New Hampshire	1
NH	3301568260	33	15	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Rockingham County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	Seabrook town	New Hampshire	1
NH	3301571140	33	15	METRO14460MM1120	Boston-Cambridge-Quincy, MA-NH HUD Metro FMR Area	Rockingham County	119000	26850	30700	34550	38350	41450	44500	47600	50650	1120	South Hampton town	New Hampshire	1
NH	3301574340	33	15	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Rockingham County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Stratham town	New Hampshire	1
NH	3301585780	33	15	METRO14460MM4160	Lawrence, MA-NH HUD Metro FMR Area	Rockingham County	98000	20600	23550	26500	29400	31800	34150	36500	38850	4160	Windham town	New Hampshire	1
NH	3301703460	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Barrington town	New Hampshire	1
NH	3301718820	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Dover city	New Hampshire	1
NH	3301719700	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Durham town	New Hampshire	1
NH	3301726020	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Farmington town	New Hampshire	1
NH	3301741460	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Lee town	New Hampshire	1
NH	3301744820	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Madbury town	New Hampshire	1
NH	3301747700	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	9999	Middleton town	New Hampshire	1
NH	3301748660	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Milton town	New Hampshire	1
NH	3301751220	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	9999	New Durham town	New Hampshire	1
NH	3301765140	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Rochester city	New Hampshire	1
NH	3301765540	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Rollinsford town	New Hampshire	1
NH	3301769940	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	6450	Somersworth city	New Hampshire	1
NH	3301773860	33	17	METRO14460MM6450	Portsmouth-Rochester, NH HUD Metro FMR Area	Strafford County	102800	21350	24400	27450	30500	32950	35400	37850	40300	9999	Strafford town	New Hampshire	1
NH	3301900260	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Acworth town	New Hampshire	0
NH	3301911380	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Charlestown town	New Hampshire	0
NH	3301912900	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Claremont city	New Hampshire	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NH	3301915060	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Cornish town	New Hampshire	0
NH	3301916340	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Croydon town	New Hampshire	0
NH	3301930500	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Goshen town	New Hampshire	0
NH	3301931220	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Grantham town	New Hampshire	0
NH	3301940900	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Langdon town	New Hampshire	0
NH	3301941700	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Lempster town	New Hampshire	0
NH	3301952580	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Newport town	New Hampshire	0
NH	3301962340	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Plainfield town	New Hampshire	0
NH	3301972740	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Springfield town	New Hampshire	0
NH	3301975060	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Sunapee town	New Hampshire	0
NH	3301977940	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Unity town	New Hampshire	0
NH	3301978980	33	19	NCNTY33019N33019	Sullivan County, NH	Sullivan County	76900	17950	20500	23050	25600	27650	29700	31750	33800	9999	Washington town	New Hampshire	0
NJ	3400199999	34	1	METRO12100M12100	Atlantic City-Hammonton, NJ MSA	Atlantic County	84300	17450	19950	22450	24900	26900	28900	30900	32900	560	Atlantic County	New Jersey	1
NJ	3400399999	34	3	METRO35620MM0875	Bergen-Passaic, NJ HUD Metro FMR Area	Bergen County	104200	21900	25000	28150	31250	33750	36250	38750	41250	875	Bergen County	New Jersey	1
NJ	3400599999	34	5	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Burlington County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Burlington County	New Jersey	1
NJ	3400799999	34	7	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Camden County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Camden County	New Jersey	1
NJ	3400999999	34	9	METRO36140M36140	Ocean City, NJ MSA	Cape May County	85800	18050	20600	23200	25750	27850	29900	31950	34000	560	Cape May County	New Jersey	1
NJ	3401199999	34	11	METRO47220M47220	Vineland-Bridgeton, NJ MSA	Cumberland County	67700	15400	17600	19800	22000	23800	25550	27300	29050	8760	Cumberland County	New Jersey	1
NJ	3401399999	34	13	METRO35620MM5640	Newark, NJ HUD Metro FMR Area	Essex County	106000	22300	25450	28650	31800	34350	36900	39450	42000	5640	Essex County	New Jersey	1
NJ	3401599999	34	15	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Gloucester County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Gloucester County	New Jersey	1
NJ	3401799999	34	17	METRO35620MM3640	Jersey City, NJ HUD Metro FMR Area	Hudson County	76900	20750	23700	26650	29600	32000	34350	36750	39100	3640	Hudson County	New Jersey	1
NJ	3401999999	34	19	METRO35620MM5015	Middlesex-Somerset-Hunterdon, NJ HUD Metro FMR Area	Hunterdon County	119500	25100	28700	32300	35850	38750	41600	44500	47350	5015	Hunterdon County	New Jersey	1
NJ	3402199999	34	21	METRO45940M45940	Trenton, NJ MSA	Mercer County	108700	22850	26100	29350	32600	35250	37850	40450	43050	8480	Mercer County	New Jersey	1
NJ	3402399999	34	23	METRO35620MM5015	Middlesex-Somerset-Hunterdon, NJ HUD Metro FMR Area	Middlesex County	119500	25100	28700	32300	35850	38750	41600	44500	47350	5015	Middlesex County	New Jersey	1
NJ	3402599999	34	25	METRO35620MM5190	Monmouth-Ocean, NJ HUD Metro FMR Area	Monmouth County	109400	23000	26250	29550	32800	35450	38050	40700	43300	5190	Monmouth County	New Jersey	1
NJ	3402799999	34	27	METRO35620MM5640	Newark, NJ HUD Metro FMR Area	Morris County	106000	22300	25450	28650	31800	34350	36900	39450	42000	5640	Morris County	New Jersey	1
NJ	3402999999	34	29	METRO35620MM5190	Monmouth-Ocean, NJ HUD Metro FMR Area	Ocean County	109400	23000	26250	29550	32800	35450	38050	40700	43300	5190	Ocean County	New Jersey	1
NJ	3403199999	34	31	METRO35620MM0875	Bergen-Passaic, NJ HUD Metro FMR Area	Passaic County	104200	21900	25000	28150	31250	33750	36250	38750	41250	875	Passaic County	New Jersey	1
NJ	3403399999	34	33	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Salem County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Salem County	New Jersey	1
NJ	3403599999	34	35	METRO35620MM5015	Middlesex-Somerset-Hunterdon, NJ HUD Metro FMR Area	Somerset County	119500	25100	28700	32300	35850	38750	41600	44500	47350	5015	Somerset County	New Jersey	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NJ	3403799999	34	37	METRO35620MM5640	Newark, NJ HUD Metro FMR Area	Sussex County	106000	22300	25450	28650	31800	34350	36900	39450	42000	5640	Sussex County	New Jersey	1
NJ	3403999999	34	39	METRO35620MM5640	Newark, NJ HUD Metro FMR Area	Union County	106000	22300	25450	28650	31800	34350	36900	39450	42000	5640	Union County	New Jersey	1
NJ	3404199999	34	41	METRO10900MM5640	Warren County, NJ HUD Metro FMR Area	Warren County	97800	20650	23600	26550	29500	31900	34250	36600	38950	5640	Warren County	New Jersey	1
NM	3500199999	35	1	METRO10740M10740	Albuquerque, NM MSA	Bernalillo County	69100	14550	16600	18700	20750	22450	24100	25750	27400	200	Bernalillo County	New Mexico	1
NM	3500399999	35	3	NCNTY35003N35003	Catron County, NM	Catron County	55200	11600	13250	14900	16550	17900	19200	20550	21850	9999	Catron County	New Mexico	0
NM	3500599999	35	5	NCNTY35005N35005	Chaves County, NM	Chaves County	57000	12000	13700	15400	17100	18500	19850	21250	22600	9999	Chaves County	New Mexico	0
NM	3500699999	35	6	NCNTY35006N35006	Cibola County, NM	Cibola County	48500	11550	13200	14850	16450	17800	19100	20400	21750	9999	Cibola County	New Mexico	0
NM	3500799999	35	7	NCNTY35007N35007	Colfax County, NM	Colfax County	49700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Colfax County	New Mexico	0
NM	3500999999	35	9	NCNTY35009N35009	Curry County, NM	Curry County	51700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Curry County	New Mexico	0
NM	3501199999	35	11	NCNTY35011N35011	De Baca County, NM	De Baca County	54900	11550	13200	14850	16450	17800	19100	20400	21750	9999	De Baca County	New Mexico	0
NM	3501399999	35	13	METRO29740M29740	Las Cruces, NM MSA	Dona Ana County	52100	11550	13200	14850	16450	17800	19100	20400	21750	4100	Dona Ana County	New Mexico	1
NM	3501599999	35	15	NCNTY35015N35015	Eddy County, NM	Eddy County	70700	14850	17000	19100	21200	22900	24600	26300	28000	9999	Eddy County	New Mexico	0
NM	3501799999	35	17	NCNTY35017N35017	Grant County, NM	Grant County	53800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Grant County	New Mexico	0
NM	3501999999	35	19	NCNTY35019N35019	Guadalupe County, NM	Guadalupe County	45200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Guadalupe County	New Mexico	0
NM	3502199999	35	21	NCNTY35021N35021	Harding County, NM	Harding County	55000	11550	13200	14850	16500	17850	19150	20500	21800	9999	Harding County	New Mexico	0
NM	3502399999	35	23	NCNTY35023N35023	Hidalgo County, NM	Hidalgo County	49900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Hidalgo County	New Mexico	0
NM	3502599999	35	25	NCNTY35025N35025	Lea County, NM	Lea County	64300	13550	15450	17400	19300	20850	22400	23950	25500	9999	Lea County	New Mexico	0
NM	3502799999	35	27	NCNTY35027N35027	Lincoln County, NM	Lincoln County	60000	12400	14200	15950	17700	19150	20550	21950	23400	9999	Lincoln County	New Mexico	0
NM	3502899999	35	28	NCNTY35028N35028	Los Alamos County, NM	Los Alamos County	141800	26400	30200	33950	37700	40750	43750	46750	49800	7490	Los Alamos County	New Mexico	0
NM	3502999999	35	29	NCNTY35029N35029	Luna County, NM	Luna County	38200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Luna County	New Mexico	0
NM	3503199999	35	31	NCNTY35031N35031	McKinley County, NM	McKinley County	36600	11550	13200	14850	16450	17800	19100	20400	21750	9999	McKinley County	New Mexico	0
NM	3503399999	35	33	NCNTY35033N35033	Mora County, NM	Mora County	40100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Mora County	New Mexico	0
NM	3503599999	35	35	NCNTY35035N35035	Otero County, NM	Otero County	57200	12050	13750	15450	17150	18550	19900	21300	22650	9999	Otero County	New Mexico	0
NM	3503799999	35	37	NCNTY35037N35037	Quay County, NM	Quay County	41500	11550	13200	14850	16450	17800	19100	20400	21750	9999	Quay County	New Mexico	0
NM	3503999999	35	39	NCNTY35039N35039	Rio Arriba County, NM	Rio Arriba County	48200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Rio Arriba County	New Mexico	0
NM	3504199999	35	41	NCNTY35041N35041	Roosevelt County, NM	Roosevelt County	47000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Roosevelt County	New Mexico	0
NM	3504399999	35	43	METRO10740M10740	Albuquerque, NM MSA	Sandoval County	69100	14550	16600	18700	20750	22450	24100	25750	27400	200	Sandoval County	New Mexico	1
NM	3504599999	35	45	METRO22140M22140	Farmington, NM MSA	San Juan County	54700	13200	15100	17000	18850	20400	21900	23400	24900	9999	San Juan County	New Mexico	1
NM	3504799999	35	47	NCNTY35047N35047	San Miguel County, NM	San Miguel County	43100	11550	13200	14850	16450	17800	19100	20400	21750	9999	San Miguel County	New Mexico	0
NM	3504999999	35	49	METRO42140M42140	Santa Fe, NM MSA	Santa Fe County	76000	16000	18250	20550	22800	24650	26450	28300	30100	7490	Santa Fe County	New Mexico	1
NM	3505199999	35	51	NCNTY35051N35051	Sierra County, NM	Sierra County	43400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Sierra County	New Mexico	0
NM	3505399999	35	53	NCNTY35053N35053	Socorro County, NM	Socorro County	46900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Socorro County	New Mexico	0
NM	3505599999	35	55	NCNTY35055N35055	Taos County, NM	Taos County	48800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Taos County	New Mexico	0
NM	3505799999	35	57	METRO10740M10740	Albuquerque, NM MSA	Torrance County	69100	14550	16600	18700	20750	22450	24100	25750	27400	9999	Torrance County	New Mexico	1
NM	3505999999	35	59	NCNTY35059N35059	Union County, NM	Union County	58400	12250	14000	15750	17450	18850	20250	21650	23050	9999	Union County	New Mexico	0
NM	3506199999	35	61	METRO10740M10740	Albuquerque, NM MSA	Valencia County	69100	14550	16600	18700	20750	22450	24100	25750	27400	200	Valencia County	New Mexico	1
NY	3600199999	36	1	METRO10580M10580	Albany-Schenectady-Troy, NY MSA	Albany County	99200	20400	23300	26200	29100	31450	33800	36100	38450	160	Albany County	New York	1
NY	3600399999	36	3	NCNTY36003N36003	Allegany County, NY	Allegany County	58700	14150	16150	18150	20150	21800	23400	25000	26600	9999	Allegany County	New York	0
NY	3600599999	36	5	METRO35620MM5600	New York, NY HUD Metro FMR Area	Bronx County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5600	Bronx County	New York	1
NY	3600799999	36	7	METRO13780M13780	Binghamton, NY MSA	Broome County	76900	16000	18300	20600	22850	24700	26550	28350	30200	960	Broome County	New York	1
NY	3600999999	36	9	NCNTY36009N36009	Cattaraugus County, NY	Cattaraugus County	65700	14150	16150	18150	20150	21800	23400	25000	26600	9999	Cattaraugus County	New York	0
NY	3601199999	36	11	NCNTY36011N36011	Cayuga County, NY	Cayuga County	71100	14950	17100	19250	21350	23100	24800	26500	28200	8160	Cayuga County	New York	0
NY	3601399999	36	13	NCNTY36013N36013	Chautauqua County, NY	Chautauqua County	58600	14150	16150	18150	20150	21800	23400	25000	26600	3610	Chautauqua County	New York	0
NY	3601599999	36	15	METRO21300M21300	Elmira, NY MSA	Chemung County	73600	15500	17700	19900	22100	23900	25650	27450	29200	2335	Chemung County	New York	1
NY	3601799999	36	17	NCNTY36017N36017	Chenango County, NY	Chenango County	63900	14150	16150	18150	20150	21800	23400	25000	26600	9999	Chenango County	New York	0
NY	3601999999	36	19	NCNTY36019N36019	Clinton County, NY	Clinton County	76800	15500	17700	19900	22100	23900	25650	27450	29200	9999	Clinton County	New York	0
NY	3602199999	36	21	NCNTY36021N36021	Columbia County, NY	Columbia County	81300	17100	19550	22000	24400	26400	28350	30300	32250	9999	Columbia County	New York	0
NY	3602399999	36	23	NCNTY36023N36023	Cortland County, NY	Cortland County	72300	15200	17400	19550	21700	23450	25200	26950	28650	9999	Cortland County	New York	0
NY	3602599999	36	25	NCNTY36025N36025	Delaware County, NY	Delaware County	64300	14150	16150	18150	20150	21800	23400	25000	26600	9999	Delaware County	New York	0
NY	3602799999	36	27	METRO35620M39100	Poughkeepsie-Newburgh-Middletown, NY HUD Metro FMR Area	Dutchess County	102300	21500	24600	27650	30700	33200	35650	38100	40550	2281	Dutchess County	New York	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NY	3602999999	36	29	METRO15380M15380	Buffalo-Cheektowaga-Niagara Falls, NY MSA	Erie County	77600	16350	18650	21000	23300	25200	27050	28900	30800	1280	Erie County	New York	1
NY	3603199999	36	31	NCNTY36031N36031	Essex County, NY	Essex County	73700	15500	17700	19900	22100	23900	25650	27450	29200	9999	Essex County	New York	0
NY	3603399999	36	33	NCNTY36033N36033	Franklin County, NY	Franklin County	65200	14150	16150	18150	20150	21800	23400	25000	26600	9999	Franklin County	New York	0
NY	3603599999	36	35	NCNTY36035N36035	Fulton County, NY	Fulton County	63000	14150	16150	18150	20150	21800	23400	25000	26600	9999	Fulton County	New York	0
NY	3603799999	36	37	NCNTY36037N36037	Genesee County, NY	Genesee County	73700	15500	17700	19900	22100	23900	25650	27450	29200	6840	Genesee County	New York	0
NY	3603999999	36	39	NCNTY36039N36039	Greene County, NY	Greene County	73800	15550	17750	19950	22150	23950	25700	27500	29250	9999	Greene County	New York	0
NY	3604199999	36	41	NCNTY36041N36041	Hamilton County, NY	Hamilton County	68400	14350	16400	18450	20500	22150	23800	25450	27100	9999	Hamilton County	New York	0
NY	3604399999	36	43	METRO46540M46540	Utica-Rome, NY MSA	Herkimer County	71700	15050	17200	19350	21500	23250	24950	26700	28400	8680	Herkimer County	New York	1
NY	3604599999	36	45	METRO48060M48060	Watertown-Fort Drum, NY MSA	Jefferson County	59500	14150	16150	18150	20150	21800	23400	25000	26600	9999	Jefferson County	New York	1
NY	3604799999	36	47	METRO35620MM5600	New York, NY HUD Metro FMR Area	Kings County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5600	Kings County	New York	1
NY	3604999999	36	49	NCNTY36049N36049	Lewis County, NY	Lewis County	65600	14150	16150	18150	20150	21800	23400	25000	26600	9999	Lewis County	New York	0
NY	3605199999	36	51	METRO40380M40380	Rochester, NY HUD Metro FMR Area	Livingston County	76400	16050	18350	20650	22900	24750	26600	28400	30250	6840	Livingston County	New York	1
NY	3605399999	36	53	METRO45060M45060	Syracuse, NY MSA	Madison County	75800	15950	18200	20500	22750	24600	26400	28250	30050	8160	Madison County	New York	1
NY	3605599999	36	55	METRO40380M40380	Rochester, NY HUD Metro FMR Area	Monroe County	76400	16050	18350	20650	22900	24750	26600	28400	30250	6840	Monroe County	New York	1
NY	3605799999	36	57	NCNTY36057N36057	Montgomery County, NY	Montgomery County	62600	14150	16150	18150	20150	21800	23400	25000	26600	160	Montgomery County	New York	0
NY	3605999999	36	59	METRO35620MM5380	Nassau-Suffolk, NY HUD Metro FMR Area	Nassau County	126600	26600	30400	34200	38000	41050	44100	47150	50200	5380	Nassau County	New York	1
NY	3606199999	36	61	METRO35620MM5600	New York, NY HUD Metro FMR Area	New York County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5600	New York County	New York	1
NY	3606399999	36	63	METRO15380M15380	Buffalo-Cheektowaga-Niagara Falls, NY MSA	Niagara County	77600	16350	18650	21000	23300	25200	27050	28900	30800	1280	Niagara County	New York	1
NY	3606599999	36	65	METRO46540M46540	Utica-Rome, NY MSA	Oneida County	71700	15050	17200	19350	21500	23250	24950	26700	28400	8680	Oneida County	New York	1
NY	3606799999	36	67	METRO45060M45060	Syracuse, NY MSA	Onondaga County	75800	15950	18200	20500	22750	24600	26400	28250	30050	8160	Onondaga County	New York	1
NY	3606999999	36	69	METRO40380M40380	Rochester, NY HUD Metro FMR Area	Ontario County	76400	16050	18350	20650	22900	24750	26600	28400	30250	6840	Ontario County	New York	1
NY	3607199999	36	71	METRO35620M39100	Poughkeepsie-Newburgh-Middletown, NY HUD Metro FMR Area	Orange County	102300	21500	24600	27650	30700	33200	35650	38100	40550	5660	Orange County	New York	1
NY	3607399999	36	73	METRO40380M40380	Rochester, NY HUD Metro FMR Area	Orleans County	76400	16050	18350	20650	22900	24750	26600	28400	30250	6840	Orleans County	New York	1
NY	3607599999	36	75	METRO45060M45060	Syracuse, NY MSA	Oswego County	75800	15950	18200	20500	22750	24600	26400	28250	30050	8160	Oswego County	New York	1
NY	3607799999	36	77	NCNTY36077N36077	Otsego County, NY	Otsego County	68100	14350	16400	18450	20450	22100	23750	25400	27000	9999	Otsego County	New York	0
NY	3607999999	36	79	METRO35620MM5600	New York, NY HUD Metro FMR Area	Putnam County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5600	Putnam County	New York	1
NY	3608199999	36	81	METRO35620MM5600	New York, NY HUD Metro FMR Area	Queens County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5600	Queens County	New York	1
NY	3608399999	36	83	METRO10580M10580	Albany-Schenectady-Troy, NY MSA	Rensselaer County	99200	20400	23300	26200	29100	31450	33800	36100	38450	160	Rensselaer County	New York	1
NY	3608599999	36	85	METRO35620MM5600	New York, NY HUD Metro FMR Area	Richmond County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5600	Richmond County	New York	1
NY	3608799998	36	87	METRO35620MM5600	New York, NY HUD Metro FMR Area	Rockland County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5602	Rockland County	New York	1
NY	3608799999	36	87	METRO40525M40525	Rockland County, NY HUD Metro FMR Area	Rockland County	111900	23900	27300	30700	34100	36850	39600	42300	45050	5602	Rockland County	New York	1
NY	3608999999	36	89	NCNTY36089N36089	St. Lawrence County, NY	St. Lawrence County	60500	14150	16150	18150	20150	21800	23400	25000	26600	9999	St. Lawrence County	New York	0
NY	3609199999	36	91	METRO10580M10580	Albany-Schenectady-Troy, NY MSA	Saratoga County	99200	20400	23300	26200	29100	31450	33800	36100	38450	160	Saratoga County	New York	1
NY	3609399999	36	93	METRO10580M10580	Albany-Schenectady-Troy, NY MSA	Schenectady County	99200	20400	23300	26200	29100	31450	33800	36100	38450	160	Schenectady County	New York	1
NY	3609599999	36	95	METRO10580M10580	Albany-Schenectady-Troy, NY MSA	Schoharie County	99200	20400	23300	26200	29100	31450	33800	36100	38450	160	Schoharie County	New York	1
NY	3609799999	36	97	NCNTY36097N36097	Schuyler County, NY	Schuyler County	66700	14150	16150	18150	20150	21800	23400	25000	26600	9999	Schuyler County	New York	0
NY	3609999999	36	99	NCNTY36099N36099	Seneca County, NY	Seneca County	69700	14650	16750	18850	20900	22600	24250	25950	27600	9999	Seneca County	New York	0
NY	3610199999	36	101	NCNTY36101N36101	Steuben County, NY	Steuben County	64600	14150	16150	18150	20150	21800	23400	25000	26600	9999	Steuben County	New York	0
NY	3610399999	36	103	METRO35620MM5380	Nassau-Suffolk, NY HUD Metro FMR Area	Suffolk County	126600	26600	30400	34200	38000	41050	44100	47150	50200	5380	Suffolk County	New York	1
NY	3610599999	36	105	NCNTY36105N36105	Sullivan County, NY	Sullivan County	75500	15900	18150	20400	22650	24500	26300	28100	29900	9999	Sullivan County	New York	0
NY	3610799999	36	107	METRO13780M13780	Binghamton, NY MSA	Tioga County	76900	16000	18300	20600	22850	24700	26550	28350	30200	960	Tioga County	New York	1
NY	3610999999	36	109	METRO27060M27060	Ithaca, NY MSA	Tompkins County	85600	18000	20600	23150	25700	27800	29850	31900	33950	9999	Tompkins County	New York	1
NY	3611199999	36	111	METRO28740M28740	Kingston, NY MSA	Ulster County	83700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Ulster County	New York	1
NY	3611399999	36	113	METRO24020M24020	Glens Falls, NY MSA	Warren County	76600	15800	18050	20300	22550	24400	26200	28000	29800	2975	Warren County	New York	1
NY	3611599999	36	115	METRO24020M24020	Glens Falls, NY MSA	Washington County	76600	15800	18050	20300	22550	24400	26200	28000	29800	2975	Washington County	New York	1
NY	3611799999	36	117	METRO40380M40380	Rochester, NY HUD Metro FMR Area	Wayne County	76400	16050	18350	20650	22900	24750	26600	28400	30250	6840	Wayne County	New York	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
NY	3611999998	36	119	METRO35620MM5600	New York, NY HUD Metro FMR Area	Westchester County	78700	23900	27300	30700	34100	36850	39600	42300	45050	5600	Westchester County	New York	1
NY	3611999999	36	119	METRO48325M48325	Westchester County, NY Statutory Exception Area	Westchester County	125800	26450	30200	34000	37750	40800	43800	46850	49850	5601	Westchester County	New York	1
NY	3612199999	36	121	NCNTY36121N36121	Wyoming County, NY	Wyoming County	70700	14850	17000	19100	21200	22900	24600	26300	28000	9999	Wyoming County	New York	0
NY	3612399999	36	123	METRO40380N36123	Yates County, NY HUD Metro FMR Area	Yates County	70600	14850	17000	19100	21200	22900	24600	26300	28000	9999	Yates County	New York	1
NC	3700199999	37	1	METRO15500M15500	Burlington, NC MSA	Alamance County	64200	13500	15400	17350	19250	20800	22350	23900	25450	3120	Alamance County	North Carolina	1
NC	3700399999	37	3	METRO25860M25860	Hickory-Lenoir-Morganton, NC MSA	Alexander County	61000	12500	14300	16100	17850	19300	20750	22150	23600	3290	Alexander County	North Carolina	1
NC	3700599999	37	5	NCNTY37005N37005	Alleghany County, NC	Alleghany County	47900	12250	14000	15750	17450	18850	20250	21650	23050	9999	Alleghany County	North Carolina	0
NC	3700799999	37	7	NCNTY37007N37007	Anson County, NC	Anson County	49100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Anson County	North Carolina	0
NC	3700999999	37	9	NCNTY37009N37009	Ashe County, NC	Ashe County	52900	12250	14000	15750	17450	18850	20250	21650	23050	9999	Ashe County	North Carolina	0
NC	3701199999	37	11	NCNTY37011N37011	Avery County, NC	Avery County	48600	12250	14000	15750	17450	18850	20250	21650	23050	9999	Avery County	North Carolina	0
NC	3701399999	37	13	NCNTY37013N37013	Beaufort County, NC	Beaufort County	58300	12250	14000	15750	17500	18900	20300	21700	23100	9999	Beaufort County	North Carolina	0
NC	3701599999	37	15	NCNTY37015N37015	Bertie County, NC	Bertie County	45000	12250	14000	15750	17450	18850	20250	21650	23050	9999	Bertie County	North Carolina	0
NC	3701799999	37	17	NCNTY37017N37017	Bladen County, NC	Bladen County	48600	12250	14000	15750	17450	18850	20250	21650	23050	9999	Bladen County	North Carolina	0
NC	3701999999	37	19	METRO34820M48900	Brunswick County, NC HUD Metro FMR Area	Brunswick County	71600	15050	17200	19350	21450	23200	24900	26600	28350	9200	Brunswick County	North Carolina	1
NC	3702199999	37	21	METRO11700M11700	Asheville, NC HUD Metro FMR Area	Buncombe County	72500	15050	17200	19350	21500	23250	24950	26700	28400	480	Buncombe County	North Carolina	1
NC	3702399999	37	23	METRO25860M25860	Hickory-Lenoir-Morganton, NC MSA	Burke County	61000	12500	14300	16100	17850	19300	20750	22150	23600	3290	Burke County	North Carolina	1
NC	3702599999	37	25	METRO16740M16740	Charlotte-Concord-Gastonia, NC-SC HUD Metro FMR Area	Cabarrus County	83500	17550	20050	22550	25050	27100	29100	31100	33100	1520	Cabarrus County	North Carolina	1
NC	3702799999	37	27	METRO25860M25860	Hickory-Lenoir-Morganton, NC MSA	Caldwell County	61000	12500	14300	16100	17850	19300	20750	22150	23600	3290	Caldwell County	North Carolina	1
NC	3702999999	37	29	NCNTY37029N37029	Camden County, NC	Camden County	78200	16450	18800	21150	23450	25350	27250	29100	31000	9999	Camden County	North Carolina	0
NC	3703199999	37	31	NCNTY37031N37031	Carteret County, NC	Carteret County	68900	14500	16550	18600	20650	22350	24000	25650	27300	9999	Carteret County	North Carolina	0
NC	3703399999	37	33	NCNTY37033N37033	Caswell County, NC	Caswell County	54000	12250	14000	15750	17450	18850	20250	21650	23050	9999	Caswell County	North Carolina	0
NC	3703599999	37	35	METRO25860M25860	Hickory-Lenoir-Morganton, NC MSA	Catawba County	61000	12500	14300	16100	17850	19300	20750	22150	23600	3290	Catawba County	North Carolina	1
NC	3703799999	37	37	METRO20500M20500	Durham-Chapel Hill, NC HUD Metro FMR Area	Chatham County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6640	Chatham County	North Carolina	1
NC	3703999999	37	39	NCNTY37039N37039	Cherokee County, NC	Cherokee County	51100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Cherokee County	North Carolina	0
NC	3704199999	37	41	NCNTY37041N37041	Chowan County, NC	Chowan County	52300	12250	14000	15750	17450	18850	20250	21650	23050	9999	Chowan County	North Carolina	0
NC	3704399999	37	43	NCNTY37043N37043	Clay County, NC	Clay County	50100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Clay County	North Carolina	0
NC	3704599999	37	45	NCNTY37045N37045	Cleveland County, NC	Cleveland County	52300	12250	14000	15750	17450	18850	20250	21650	23050	9999	Cleveland County	North Carolina	0

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NC	3704799999	37	47	NCNTY37047N37047	Columbus County, NC	Columbus County	49600	12250	14000	15750	17450	18850	20250	21650	23050	9999	Columbus County	North Carolina	0
NC	3704999999	37	49	METRO35100N37049	Craven County, NC HUD Metro FMR Area	Craven County	66200	13900	15900	17900	19850	21450	23050	24650	26250	9999	Craven County	North Carolina	1
NC	3705199999	37	51	METRO22180M22180	Fayetteville, NC HUD Metro FMR Area	Cumberland County	58000	12250	14000	15750	17450	18850	20250	21650	23050	2560	Cumberland County	North Carolina	1
NC	3705399999	37	53	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Currituck County	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Currituck County	North Carolina	1
NC	3705599999	37	55	NCNTY37055N37055	Dare County, NC	Dare County	69400	14600	16650	18750	20800	22500	24150	25800	27500	9999	Dare County	North Carolina	0
NC	3705799999	37	57	METRO49180N37057	Davidson County, NC HUD Metro FMR Area	Davidson County	59300	12500	14250	16050	17800	19250	20650	22100	23500	3120	Davidson County	North Carolina	1
NC	3705999999	37	59	METRO49180M49180	Winston-Salem, NC HUD Metro FMR Area	Davie County	68600	14050	16050	18050	20050	21700	23300	24900	26500	3120	Davie County	North Carolina	1
NC	3706199999	37	61	NCNTY37061N37061	Duplin County, NC	Duplin County	46400	12250	14000	15750	17450	18850	20250	21650	23050	9999	Duplin County	North Carolina	0
NC	3706399999	37	63	METRO20500M20500	Durham-Chapel Hill, NC HUD Metro FMR Area	Durham County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6640	Durham County	North Carolina	1
NC	3706599999	37	65	METRO40580M40580	Rocky Mount, NC MSA	Edgecombe County	57700	12250	14000	15750	17450	18850	20250	21650	23050	6895	Edgecombe County	North Carolina	1
NC	3706799999	37	67	METRO49180M49180	Winston-Salem, NC HUD Metro FMR Area	Forsyth County	68600	14050	16050	18050	20050	21700	23300	24900	26500	3120	Forsyth County	North Carolina	1
NC	3706999999	37	69	METRO39580M39580	Raleigh, NC MSA	Franklin County	94100	19800	22600	25450	28250	30550	32800	35050	37300	6640	Franklin County	North Carolina	1
NC	3707199999	37	71	METRO16740M16740	Charlotte-Concord-Gastonia, NC-SC HUD Metro FMR Area	Gaston County	83500	17550	20050	22550	25050	27100	29100	31100	33100	1520	Gaston County	North Carolina	1
NC	3707399999	37	73	METRO47260N37073	Gates County, NC HUD Metro FMR Area	Gates County	68000	14300	16350	18400	20400	22050	23700	25300	26950	9999	Gates County	North Carolina	1
NC	3707599999	37	75	NCNTY37075N37075	Graham County, NC	Graham County	49400	12250	14000	15750	17450	18850	20250	21650	23050	9999	Graham County	North Carolina	0
NC	3707799999	37	77	NCNTY37077N37077	Granville County, NC	Granville County	65300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Granville County	North Carolina	0
NC	3707999999	37	79	NCNTY37079N37079	Greene County, NC	Greene County	54100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Greene County	North Carolina	0
NC	3708199999	37	81	METRO24660M24660	Greensboro-High Point, NC HUD Metro FMR Area	Guilford County	66600	13900	15900	17900	19850	21450	23050	24650	26250	3120	Guilford County	North Carolina	1
NC	3708399999	37	83	NCNTY37083N37083	Halifax County, NC	Halifax County	45200	12250	14000	15750	17450	18850	20250	21650	23050	9999	Halifax County	North Carolina	0
NC	3708599999	37	85	NCNTY37085N37085	Harnett County, NC	Harnett County	64800	13650	15600	17550	19450	21050	22600	24150	25700	9999	Harnett County	North Carolina	0
NC	3708799999	37	87	METRO11700N37087	Haywood County, NC HUD Metro FMR Area	Haywood County	60400	12700	14500	16300	18100	19550	21000	22450	23900	9999	Haywood County	North Carolina	1
NC	3708999999	37	89	METRO11700M11700	Asheville, NC HUD Metro FMR Area	Henderson County	72500	15050	17200	19350	21500	23250	24950	26700	28400	9999	Henderson County	North Carolina	1
NC	3709199999	37	91	NCNTY37091N37091	Hertford County, NC	Hertford County	46100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Hertford County	North Carolina	0
NC	3709399999	37	93	METRO22180N37093	Hoke County, NC HUD Metro FMR Area	Hoke County	54800	12250	14000	15750	17450	18850	20250	21650	23050	9999	Hoke County	North Carolina	1
NC	3709599999	37	95	NCNTY37095N37095	Hyde County, NC	Hyde County	58100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Hyde County	North Carolina	0

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NC	3709799999	37	97	METRO16740N37097	Iredell County, NC HUD Metro FMR Area	Iredell County	73100	15400	17600	19800	21950	23750	25500	27250	29000	9999	Iredell County	North Carolina	1
NC	3709999999	37	99	NCNTY37099N37099	Jackson County, NC	Jackson County	60700	12750	14550	16350	18150	19650	21100	22550	24000	9999	Jackson County	North Carolina	0
NC	3710199999	37	101	METRO39580M39580	Raleigh, NC MSA	Johnston County	94100	19800	22600	25450	28250	30550	32800	35050	37300	6640	Johnston County	North Carolina	1
NC	3710399999	37	103	METRO35100N37103	Jones County, NC HUD Metro FMR Area	Jones County	50100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Jones County	North Carolina	1
NC	3710599999	37	105	NCNTY37105N37105	Lee County, NC	Lee County	62100	13100	14950	16800	18650	20150	21650	23150	24650	9999	Lee County	North Carolina	0
NC	3710799999	37	107	NCNTY37107N37107	Lenoir County, NC	Lenoir County	51300	12250	14000	15750	17450	18850	20250	21650	23050	9999	Lenoir County	North Carolina	0
NC	3710999999	37	109	METRO16740N37109	Lincoln County, NC HUD Metro FMR Area	Lincoln County	65500	13800	15750	17700	19650	21250	22800	24400	25950	1520	Lincoln County	North Carolina	1
NC	3711199999	37	111	NCNTY37111N37111	McDowell County, NC	McDowell County	49100	12250	14000	15750	17450	18850	20250	21650	23050	9999	McDowell County	North Carolina	0
NC	3711399999	37	113	NCNTY37113N37113	Macon County, NC	Macon County	54300	12250	14000	15750	17450	18850	20250	21650	23050	9999	Macon County	North Carolina	0
NC	3711599999	37	115	METRO11700M11700	Asheville, NC HUD Metro FMR Area	Madison County	72500	15050	17200	19350	21500	23250	24950	26700	28400	480	Madison County	North Carolina	1
NC	3711799999	37	117	NCNTY37117N37117	Martin County, NC	Martin County	46500	12250	14000	15750	17450	18850	20250	21650	23050	9999	Martin County	North Carolina	0
NC	3711999999	37	119	METRO16740M16740	Charlotte-Concord-Gastonia, NC-SC HUD Metro FMR Area	Mecklenburg County	83500	17550	20050	22550	25050	27100	29100	31100	33100	1520	Mecklenburg County	North Carolina	1
NC	3712199999	37	121	NCNTY37121N37121	Mitchell County, NC	Mitchell County	56400	12250	14000	15750	17450	18850	20250	21650	23050	9999	Mitchell County	North Carolina	0
NC	3712399999	37	123	NCNTY37123N37123	Montgomery County, NC	Montgomery County	53900	12250	14000	15750	17450	18850	20250	21650	23050	9999	Montgomery County	North Carolina	0
NC	3712599999	37	125	NCNTY37125N37125	Moore County, NC	Moore County	88200	16550	18900	21250	23600	25500	27400	29300	31200	9999	Moore County	North Carolina	0
NC	3712799999	37	127	METRO40580M40580	Rocky Mount, NC MSA	Nash County	57700	12250	14000	15750	17450	18850	20250	21650	23050	6895	Nash County	North Carolina	1
NC	3712999999	37	129	METRO48900M48900	Wilmington, NC HUD Metro FMR Area	New Hanover County	81000	16500	18850	21200	23550	25450	27350	29250	31100	9200	New Hanover County	North Carolina	1
NC	3713199999	37	131	NCNTY37131N37131	Northampton County, NC	Northampton County	43700	12250	14000	15750	17450	18850	20250	21650	23050	9999	Northampton County	North Carolina	0
NC	3713399999	37	133	METRO27340M27340	Jacksonville, NC MSA	Onslow County	57700	12250	14000	15750	17450	18850	20250	21650	23050	3605	Onslow County	North Carolina	1
NC	3713599999	37	135	METRO20500M20500	Durham-Chapel Hill, NC HUD Metro FMR Area	Orange County	90900	19100	21800	24550	27250	29450	31650	33800	36000	6640	Orange County	North Carolina	1
NC	3713799999	37	137	METRO35100N37137	Pamlico County, NC HUD Metro FMR Area	Pamlico County	60400	12700	14500	16300	18100	19550	21000	22450	23900	9999	Pamlico County	North Carolina	1
NC	3713999999	37	139	NCNTY37139N37139	Pasquotank County, NC	Pasquotank County	66200	13300	15200	17100	19000	20550	22050	23600	25100	9999	Pasquotank County	North Carolina	0
NC	3714199999	37	141	METRO48900N37141	Pender County, NC HUD Metro FMR Area	Pender County	67900	14050	16050	18050	20050	21700	23300	24900	26500	9999	Pender County	North Carolina	1
NC	3714399999	37	143	NCNTY37143N37143	Perquimans County, NC	Perquimans County	53300	12250	14000	15750	17450	18850	20250	21650	23050	9999	Perquimans County	North Carolina	0
NC	3714599999	37	145	METRO20500N37145	Person County, NC HUD Metro FMR Area	Person County	61800	12700	14500	16300	18100	19550	21000	22450	23900	9999	Person County	North Carolina	1

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NC	3714799999	37	147	METRO24780M24780	Greenville, NC MSA	Pitt County	66700	14000	16000	18000	20000	21600	23200	24800	26400	3150	Pitt County	North Carolina	1
NC	3714999999	37	149	NCNTY37149N37149	Polk County, NC	Polk County	60600	12750	14600	16400	18200	19700	21150	22600	24050	9999	Polk County	North Carolina	0
NC	3715199999	37	151	METRO24660M24660	Greensboro-High Point, NC HUD Metro FMR Area	Randolph County	66600	13900	15900	17900	19850	21450	23050	24650	26250	3120	Randolph County	North Carolina	1
NC	3715399999	37	153	NCNTY37153N37153	Richmond County, NC	Richmond County	43300	12250	14000	15750	17450	18850	20250	21650	23050	9999	Richmond County	North Carolina	0
NC	3715599999	37	155	NCNTY37155N37155	Robeson County, NC	Robeson County	46200	12250	14000	15750	17450	18850	20250	21650	23050	9999	Robeson County	North Carolina	0
NC	3715799999	37	157	METRO24660N37157	Rockingham County, NC HUD Metro FMR Area	Rockingham County	61700	12500	14300	16100	17850	19300	20750	22150	23600	9999	Rockingham County	North Carolina	1
NC	3715999999	37	159	METRO16740N37159	Rowan County, NC HUD Metro FMR Area	Rowan County	64400	13550	15450	17400	19300	20850	22400	23950	25500	1520	Rowan County	North Carolina	1
NC	3716199999	37	161	NCNTY37161N37161	Rutherford County, NC	Rutherford County	55800	12250	14000	15750	17450	18850	20250	21650	23050	9999	Rutherford County	North Carolina	0
NC	3716399999	37	163	NCNTY37163N37163	Sampson County, NC	Sampson County	49300	12250	14000	15750	17450	18850	20250	21650	23050	9999	Sampson County	North Carolina	0
NC	3716599999	37	165	NCNTY37165N37165	Scotland County, NC	Scotland County	44000	12250	14000	15750	17450	18850	20250	21650	23050	9999	Scotland County	North Carolina	0
NC	3716799999	37	167	NCNTY37167N37167	Stanly County, NC	Stanly County	60700	12750	14600	16400	18200	19700	21150	22600	24050	9999	Stanly County	North Carolina	0
NC	3716999999	37	169	METRO49180M49180	Winston-Salem, NC HUD Metro FMR Area	Stokes County	68600	14050	16050	18050	20050	21700	23300	24900	26500	3120	Stokes County	North Carolina	1
NC	3717199999	37	171	NCNTY37171N37171	Surry County, NC	Surry County	59800	12500	14300	16100	17850	19300	20750	22150	23600	9999	Surry County	North Carolina	0
NC	3717399999	37	173	NCNTY37173N37173	Swain County, NC	Swain County	47700	12250	14000	15750	17450	18850	20250	21650	23050	9999	Swain County	North Carolina	0
NC	3717599999	37	175	NCNTY37175N37175	Transylvania County, NC	Transylvania County	56700	12250	14000	15750	17450	18850	20250	21650	23050	9999	Transylvania County	North Carolina	0
NC	3717799999	37	177	NCNTY37177N37177	Tyrrell County, NC	Tyrrell County	42900	12250	14000	15750	17450	18850	20250	21650	23050	9999	Tyrrell County	North Carolina	0
NC	3717999999	37	179	METRO16740M16740	Charlotte-Concord-Gastonia, NC-SC HUD Metro FMR Area	Union County	83500	17550	20050	22550	25050	27100	29100	31100	33100	1520	Union County	North Carolina	1
NC	3718199999	37	181	NCNTY37181N37181	Vance County, NC	Vance County	48100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Vance County	North Carolina	0
NC	3718399999	37	183	METRO39580M39580	Raleigh, NC MSA	Wake County	94100	19800	22600	25450	28250	30550	32800	35050	37300	6640	Wake County	North Carolina	1
NC	3718599999	37	185	NCNTY37185N37185	Warren County, NC	Warren County	51100	12250	14000	15750	17450	18850	20250	21650	23050	9999	Warren County	North Carolina	0
NC	3718799999	37	187	NCNTY37187N37187	Washington County, NC	Washington County	50800	12250	14000	15750	17450	18850	20250	21650	23050	9999	Washington County	North Carolina	0
NC	3718999999	37	189	NCNTY37189N37189	Watauga County, NC	Watauga County	69400	14600	16650	18750	20800	22500	24150	25800	27500	9999	Watauga County	North Carolina	0
NC	3719199999	37	191	METRO24140M24140	Goldsboro, NC MSA	Wayne County	54100	12250	14000	15750	17450	18850	20250	21650	23050	2980	Wayne County	North Carolina	1
NC	3719399999	37	193	NCNTY37193N37193	Wilkes County, NC	Wilkes County	53700	12250	14000	15750	17450	18850	20250	21650	23050	9999	Wilkes County	North Carolina	0
NC	3719599999	37	195	NCNTY37195N37195	Wilson County, NC	Wilson County	61000	12850	14650	16500	18300	19800	21250	22700	24200	9999	Wilson County	North Carolina	0

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NC	3719799999	37	197	METRO49180M49180	Winston-Salem, NC HUD Metro FMR Area	Yadkin County	68600	14050	16050	18050	20050	21700	23300	24900	26500	3120	Yadkin County	North Carolina	1
NC	3719999999	37	199	NCNTY37199N37199	Yancey County, NC	Yancey County	53400	12250	14000	15750	17450	18850	20250	21650	23050	9999	Yancey County	North Carolina	0
ND	3800199999	38	1	NCNTY38001N38001	Adams County, ND	Adams County	78400	17600	20100	22600	25100	27150	29150	31150	33150	9999	Adams County	North Dakota	0
ND	3800399999	38	3	NCNTY38003N38003	Barnes County, ND	Barnes County	80700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Barnes County	North Dakota	0
ND	3800599999	38	5	NCNTY38005N38005	Benson County, ND	Benson County	52600	17600	20100	22600	25100	27150	29150	31150	33150	9999	Benson County	North Dakota	0
ND	3800799999	38	7	NCNTY38007N38007	Billings County, ND	Billings County	107700	21850	24950	28050	31150	33650	36150	38650	41150	9999	Billings County	North Dakota	0
ND	3800999999	38	9	NCNTY38009N38009	Bottineau County, ND	Bottineau County	79700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Bottineau County	North Dakota	0
ND	3801199999	38	11	NCNTY38011N38011	Bowman County, ND	Bowman County	99400	20900	23850	26850	29800	32200	34600	37000	39350	9999	Bowman County	North Dakota	0
ND	3801399999	38	13	NCNTY38013N38013	Burke County, ND	Burke County	89800	18900	21600	24300	26950	29150	31300	33450	35600	9999	Burke County	North Dakota	0
ND	3801599999	38	15	METRO13900M13900	Bismarck, ND HUD Metro FMR Area	Burleigh County	96000	20200	23050	25950	28800	31150	33450	35750	38050	1010	Burleigh County	North Dakota	1
ND	3801799999	38	17	METRO22020M22020	Fargo, ND-MN MSA	Cass County	89400	18800	21450	24150	26800	28950	31100	33250	35400	2520	Cass County	North Dakota	1
ND	3801999999	38	19	NCNTY38019N38019	Cavalier County, ND	Cavalier County	85500	18000	20550	23100	25650	27750	29800	31850	33900	9999	Cavalier County	North Dakota	0
ND	3802199999	38	21	NCNTY38021N38021	Dickey County, ND	Dickey County	77500	17600	20100	22600	25100	27150	29150	31150	33150	9999	Dickey County	North Dakota	0
ND	3802399999	38	23	NCNTY38023N38023	Divide County, ND	Divide County	93300	19600	22400	25200	28000	30250	32500	34750	37000	9999	Divide County	North Dakota	0
ND	3802599999	38	25	NCNTY38025N38025	Dunn County, ND	Dunn County	92000	19350	22100	24850	27600	29850	32050	34250	36450	9999	Dunn County	North Dakota	0
ND	3802799999	38	27	NCNTY38027N38027	Eddy County, ND	Eddy County	76600	17600	20100	22600	25100	27150	29150	31150	33150	9999	Eddy County	North Dakota	0
ND	3802999999	38	29	NCNTY38029N38029	Emmons County, ND	Emmons County	64000	17600	20100	22600	25100	27150	29150	31150	33150	9999	Emmons County	North Dakota	0
ND	3803199999	38	31	NCNTY38031N38031	Foster County, ND	Foster County	77700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Foster County	North Dakota	0
ND	3803399999	38	33	NCNTY38033N38033	Golden Valley County, ND	Golden Valley County	78600	17600	20100	22600	25100	27150	29150	31150	33150	9999	Golden Valley County	North Dakota	0
ND	3803599999	38	35	METRO24220M24220	Grand Forks, ND-MN MSA	Grand Forks County	89200	18550	21200	23850	26500	28650	30750	32900	35000	2985	Grand Forks County	North Dakota	1
ND	3803799999	38	37	NCNTY38037N38037	Grant County, ND	Grant County	75800	17600	20100	22600	25100	27150	29150	31150	33150	9999	Grant County	North Dakota	0
ND	3803999999	38	39	NCNTY38039N38039	Griggs County, ND	Griggs County	79300	17600	20100	22600	25100	27150	29150	31150	33150	9999	Griggs County	North Dakota	0
ND	3804199999	38	41	NCNTY38041N38041	Hettinger County, ND	Hettinger County	79400	17600	20100	22600	25100	27150	29150	31150	33150	9999	Hettinger County	North Dakota	0
ND	3804399999	38	43	NCNTY38043N38043	Kidder County, ND	Kidder County	66400	17600	20100	22600	25100	27150	29150	31150	33150	9999	Kidder County	North Dakota	0
ND	3804599999	38	45	NCNTY38045N38045	LaMoure County, ND	LaMoure County	78500	17600	20100	22600	25100	27150	29150	31150	33150	9999	LaMoure County	North Dakota	0
ND	3804799999	38	47	NCNTY38047N38047	Logan County, ND	Logan County	77700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Logan County	North Dakota	0
ND	3804999999	38	49	NCNTY38049N38049	McHenry County, ND	McHenry County	90800	19100	21800	24550	27250	29450	31650	33800	36000	9999	McHenry County	North Dakota	0
ND	3805199999	38	51	NCNTY38051N38051	McIntosh County, ND	McIntosh County	63600	17600	20100	22600	25100	27150	29150	31150	33150	9999	McIntosh County	North Dakota	0
ND	3805399999	38	53	NCNTY38053N38053	McKenzie County, ND	McKenzie County	99000	20800	23800	26750	29700	32100	34500	36850	39250	9999	McKenzie County	North Dakota	0
ND	3805599999	38	55	NCNTY38055N38055	McLean County, ND	McLean County	83000	17600	20100	22600	25100	27150	29150	31150	33150	9999	McLean County	North Dakota	0
ND	3805799999	38	57	NCNTY38057N38057	Mercer County, ND	Mercer County	98400	20650	23600	26550	29500	31900	34250	36600	38950	9999	Mercer County	North Dakota	0
ND	3805999999	38	59	METRO13900M13900	Bismarck, ND HUD Metro FMR Area	Morton County	96000	20200	23050	25950	28800	31150	33450	35750	38050	1010	Morton County	North Dakota	1
ND	3806199999	38	61	NCNTY38061N38061	Mountrail County, ND	Mountrail County	91700	19200	21950	24700	27400	29600	31800	34000	36200	9999	Mountrail County	North Dakota	0
ND	3806399999	38	63	NCNTY38063N38063	Nelson County, ND	Nelson County	74900	17600	20100	22600	25100	27150	29150	31150	33150	9999	Nelson County	North Dakota	0
ND	3806599999	38	65	METRO13900N38065	Oliver County, ND HUD Metro FMR Area	Oliver County	88800	18700	21350	24000	26650	28800	30950	33050	35200	9999	Oliver County	North Dakota	1
ND	3806799999	38	67	NCNTY38067N38067	Pembina County, ND	Pembina County	82700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Pembina County	North Dakota	0
ND	3806999999	38	69	NCNTY38069N38069	Pierce County, ND	Pierce County	59700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Pierce County	North Dakota	0
ND	3807199999	38	71	NCNTY38071N38071	Ramsey County, ND	Ramsey County	85900	18050	20600	23200	25750	27850	29900	31950	34000	9999	Ramsey County	North Dakota	0
ND	3807399999	38	73	NCNTY38073N38073	Ransom County, ND	Ransom County	77300	17600	20100	22600	25100	27150	29150	31150	33150	9999	Ransom County	North Dakota	0
ND	3807599999	38	75	NCNTY38075N38075	Renville County, ND	Renville County	82300	17650	20200	22700	25200	27250	29250	31250	33300	9999	Renville County	North Dakota	0
ND	3807799999	38	77	NCNTY38077N38077	Richland County, ND	Richland County	80700	17600	20100	22600	25100	27150	29150	31150	33150	9999	Richland County	North Dakota	0
ND	3807999999	38	79	NCNTY38079N38079	Rolette County, ND	Rolette County	47400	17600	20100	22600	25100	27150	29150	31150	33150	9999	Rolette County	North Dakota	0
ND	3808199999	38	81	NCNTY38081N38081	Sargent County, ND	Sargent County	87700	18450	21050	23700	26300	28450	30550	32650	34750	9999	Sargent County	North Dakota	0
ND	3808399999	38	83	NCNTY38083N38083	Sheridan County, ND	Sheridan County	63500	17600	20100	22600	25100	27150	29150	31150	33150	9999	Sheridan County	North Dakota	0
ND	3808599999	38	85	METRO13900N38085	Sioux County, ND HUD Metro FMR Area	Sioux County	44600	17600	20100	22600	25100	27150	29150	31150	33150	9999	Sioux County	North Dakota	1
ND	3808799999	38	87	NCNTY38087N38087	Slope County, ND	Slope County	84000	17650	20200	22700	25200	27250	29250	31250	33300	9999	Slope County	North Dakota	0
ND	3808999999	38	89	NCNTY38089N38089	Stark County, ND	Stark County	104300	21950	25050	28200	31300	33850	36350	38850	41350	9999	Stark County	North Dakota	0
ND	3809199999	38	91	NCNTY38091N38091	Steele County, ND	Steele County	93100	18550	21200	23850	26500	28650	30750	32900	35000	9999	Steele County	North Dakota	0

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ND	3809399999	38	93	NCNTY38093N38093	Stutsman County, ND	Stutsman County	78900	17600	20100	22600	25100	27150	29150	31150	33150	9999	Stutsman County	North Dakota	0
ND	3809599999	38	95	NCNTY38095N38095	Towner County, ND	Towner County	77800	17600	20100	22600	25100	27150	29150	31150	33150	9999	Towner County	North Dakota	0
ND	3809799999	38	97	NCNTY38097N38097	Traill County, ND	Traill County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Traill County	North Dakota	0
ND	3809999999	38	99	NCNTY38099N38099	Walsh County, ND	Walsh County	68500	17600	20100	22600	25100	27150	29150	31150	33150	9999	Walsh County	North Dakota	0
ND	3810199999	38	101	NCNTY38101N38101	Ward County, ND	Ward County	90900	18800	21450	24150	26800	28950	31100	33250	35400	9999	Ward County	North Dakota	0
ND	3810399999	38	103	NCNTY38103N38103	Wells County, ND	Wells County	77400	17600	20100	22600	25100	27150	29150	31150	33150	9999	Wells County	North Dakota	0
ND	3810599999	38	105	NCNTY38105N38105	Williams County, ND	Williams County	107400	22350	25550	28750	31900	34500	37050	39600	42150	9999	Williams County	North Dakota	0
OH	3900199999	39	1	NCNTY39001N39001	Adams County, OH	Adams County	47500	13700	15650	17600	19550	21150	22700	24250	25850	9999	Adams County	Ohio	0
OH	3900399999	39	3	METRO30620M30620	Lima, OH MSA	Allen County	67100	14150	16150	18150	20150	21800	23400	25000	26600	4320	Allen County	Ohio	1
OH	3900599999	39	5	NCNTY39005N39005	Ashland County, OH	Ashland County	67200	14150	16150	18150	20150	21800	23400	25000	26600	9999	Ashland County	Ohio	0
OH	3900799999	39	7	NCNTY39007N39007	Ashtabula County, OH	Ashtabula County	55600	13700	15650	17600	19550	21150	22700	24250	25850	1680	Ashtabula County	Ohio	0
OH	3900999999	39	9	NCNTY39009N39009	Athens County, OH	Athens County	72000	14850	16950	19050	21150	22850	24550	26250	27950	9999	Athens County	Ohio	0
OH	3901199999	39	11	NCNTY39011N39011	Auglaize County, OH	Auglaize County	76700	16100	18400	20700	23000	24850	26700	28550	30400	4320	Auglaize County	Ohio	0
OH	3901399999	39	13	METRO48540M48540	Wheeling, WV-OH MSA	Belmont County	68900	14500	16550	18600	20650	22350	24000	25650	27300	9000	Belmont County	Ohio	1
OH	3901599999	39	15	METRO17140MM1220	Brown County, OH HUD Metro FMR Area	Brown County	60200	13700	15650	17600	19550	21150	22700	24250	25850	1220	Brown County	Ohio	1
OH	3901799999	39	17	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Butler County	86300	18150	20750	23350	25900	28000	30050	32150	34200	3200	Butler County	Ohio	1
OH	3901999999	39	19	METRO15940M15940	Canton-Massillon, OH MSA	Carroll County	69500	14600	16700	18800	20850	22550	24200	25900	27550	1320	Carroll County	Ohio	1
OH	3902199999	39	21	NCNTY39021N39021	Champaign County, OH	Champaign County	68200	14350	16400	18450	20450	22100	23750	25400	27000	9999	Champaign County	Ohio	0
OH	3902399999	39	23	METRO44220M44220	Springfield, OH MSA	Clark County	61100	13700	15650	17600	19550	21150	22700	24250	25850	2000	Clark County	Ohio	1
OH	3902599999	39	25	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Clermont County	86300	18150	20750	23350	25900	28000	30050	32150	34200	1640	Clermont County	Ohio	1
OH	3902799999	39	27	NCNTY39027N39027	Clinton County, OH	Clinton County	64600	13700	15650	17600	19550	21150	22700	24250	25850	9999	Clinton County	Ohio	0
OH	3902999999	39	29	NCNTY39029N39029	Columbiana County, OH	Columbiana County	56600	13700	15650	17600	19550	21150	22700	24250	25850	9320	Columbiana County	Ohio	0
OH	3903199999	39	31	NCNTY39031N39031	Coshocton County, OH	Coshocton County	56000	13700	15650	17600	19550	21150	22700	24250	25850	9999	Coshocton County	Ohio	0
OH	3903399999	39	33	NCNTY39033N39033	Crawford County, OH	Crawford County	56600	13700	15650	17600	19550	21150	22700	24250	25850	4800	Crawford County	Ohio	0
OH	3903599999	39	35	METRO17460M17460	Cleveland-Elyria, OH MSA	Cuyahoga County	76000	16000	18250	20550	22800	24650	26450	28300	30100	1680	Cuyahoga County	Ohio	1
OH	3903799999	39	37	NCNTY39037N39037	Darke County, OH	Darke County	64300	13700	15650	17600	19550	21150	22700	24250	25850	9999	Darke County	Ohio	0
OH	3903999999	39	39	NCNTY39039N39039	Defiance County, OH	Defiance County	68700	14450	16500	18550	20600	22250	23900	25550	27200	9999	Defiance County	Ohio	0
OH	3904199999	39	41	METRO18140M18140	Columbus, OH HUD Metro FMR Area	Delaware County	84500	17700	20200	22750	25250	27300	29300	31350	33350	1840	Delaware County	Ohio	1
OH	3904399999	39	43	NCNTY39043N39043	Erie County, OH	Erie County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Erie County	Ohio	0
OH	3904599999	39	45	METRO18140M18140	Columbus, OH HUD Metro FMR Area	Fairfield County	84500	17700	20200	22750	25250	27300	29300	31350	33350	1840	Fairfield County	Ohio	1
OH	3904799999	39	47	NCNTY39047N39047	Fayette County, OH	Fayette County	56300	13700	15650	17600	19550	21150	22700	24250	25850	9999	Fayette County	Ohio	0
OH	3904999999	39	49	METRO18140M18140	Columbus, OH HUD Metro FMR Area	Franklin County	84500	17700	20200	22750	25250	27300	29300	31350	33350	1840	Franklin County	Ohio	1
OH	3905199999	39	51	METRO45780M45780	Toledo, OH MSA	Fulton County	71900	15100	17250	19400	21550	23300	25000	26750	28450	8400	Fulton County	Ohio	1
OH	3905399999	39	53	NCNTY39053N39053	Gallia County, OH	Gallia County	61600	13700	15650	17600	19550	21150	22700	24250	25850	9999	Gallia County	Ohio	0
OH	3905599999	39	55	METRO17460M17460	Cleveland-Elyria, OH MSA	Geauga County	76000	16000	18250	20550	22800	24650	26450	28300	30100	1680	Geauga County	Ohio	1
OH	3905799999	39	57	METRO19380M19380	Dayton, OH MSA	Greene County	72800	15300	17500	19700	21850	23600	25350	27100	28850	2000	Greene County	Ohio	1
OH	3905999999	39	59	NCNTY39059N39059	Guernsey County, OH	Guernsey County	55200	13700	15650	17600	19550	21150	22700	24250	25850	9999	Guernsey County	Ohio	0
OH	3906199999	39	61	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Hamilton County	86300	18150	20750	23350	25900	28000	30050	32150	34200	1640	Hamilton County	Ohio	1
OH	3906399999	39	63	NCNTY39063N39063	Hancock County, OH	Hancock County	74600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Hancock County	Ohio	0
OH	3906599999	39	65	NCNTY39065N39065	Hardin County, OH	Hardin County	63900	13700	15650	17600	19550	21150	22700	24250	25850	9999	Hardin County	Ohio	0
OH	3906799999	39	67	NCNTY39067N39067	Harrison County, OH	Harrison County	59100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Harrison County	Ohio	0
OH	3906999999	39	69	NCNTY39069N39069	Henry County, OH	Henry County	73200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Henry County	Ohio	0
OH	3907199999	39	71	NCNTY39071N39071	Highland County, OH	Highland County	55800	13700	15650	17600	19550	21150	22700	24250	25850	9999	Highland County	Ohio	0
OH	3907399999	39	73	METRO18140N39073	Hocking County, OH HUD Metro FMR Area	Hocking County	64300	13700	15650	17600	19550	21150	22700	24250	25850	9999	Hocking County	Ohio	1
OH	3907599999	39	75	NCNTY39075N39075	Holmes County, OH	Holmes County	69300	14600	16650	18750	20800	22500	24150	25800	27500	9999	Holmes County	Ohio	0
OH	3907799999	39	77	NCNTY39077N39077	Huron County, OH	Huron County	62500	13700	15650	17600	19550	21150	22700	24250	25850	9999	Huron County	Ohio	0
OH	3907999999	39	79	NCNTY39079N39079	Jackson County, OH	Jackson County	52600	13700	15650	17600	19550	21150	22700	24250	25850	9999	Jackson County	Ohio	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
OH	3908199999	39	81	METRO48260M48260	Weirton-Steubenville, WV-OH MSA	Jefferson County	62400	13700	15650	17600	19550	21150	22700	24250	25850	8080	Jefferson County	Ohio	1
OH	3908399999	39	83	NCNTY39083N39083	Knox County, OH	Knox County	65500	13800	15750	17700	19650	21250	22800	24400	25950	9999	Knox County	Ohio	0
OH	3908599999	39	85	METRO17460M17460	Cleveland-Elyria, OH MSA	Lake County	76000	16000	18250	20550	22800	24650	26450	28300	30100	1680	Lake County	Ohio	1
OH	3908799999	39	87	METRO26580M26580	Huntington-Ashland, WV-KY-OH HUD Metro FMR Area	Lawrence County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3400	Lawrence County	Ohio	1
OH	3908999999	39	89	METRO18140M18140	Columbus, OH HUD Metro FMR Area	Licking County	84500	17700	20200	22750	25250	27300	29300	31350	33350	1840	Licking County	Ohio	1
OH	3909199999	39	91	NCNTY39091N39091	Logan County, OH	Logan County	68900	14500	16550	18600	20650	22350	24000	25650	27300	9999	Logan County	Ohio	0
OH	3909399999	39	93	METRO17460M17460	Cleveland-Elyria, OH MSA	Lorain County	76000	16000	18250	20550	22800	24650	26450	28300	30100	1680	Lorain County	Ohio	1
OH	3909599999	39	95	METRO45780M45780	Toledo, OH MSA	Lucas County	71900	15100	17250	19400	21550	23300	25000	26750	28450	8400	Lucas County	Ohio	1
OH	3909799999	39	97	METRO18140M18140	Columbus, OH HUD Metro FMR Area	Madison County	84500	17700	20200	22750	25250	27300	29300	31350	33350	1840	Madison County	Ohio	1
OH	3909999999	39	99	METRO49660M49660	Youngstown-Warren-Boardman, OH HUD Metro FMR Area	Mahoning County	60700	13700	15650	17600	19550	21150	22700	24250	25850	9320	Mahoning County	Ohio	1
OH	3910199999	39	101	NCNTY39101N39101	Marion County, OH	Marion County	61100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Marion County	Ohio	0
OH	3910399999	39	103	METRO17460M17460	Cleveland-Elyria, OH MSA	Medina County	76000	16000	18250	20550	22800	24650	26450	28300	30100	1680	Medina County	Ohio	1
OH	3910599999	39	105	NCNTY39105N39105	Meigs County, OH	Meigs County	55000	13700	15650	17600	19550	21150	22700	24250	25850	9999	Meigs County	Ohio	0
OH	3910799999	39	107	NCNTY39107N39107	Mercer County, OH	Mercer County	72500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Mercer County	Ohio	0
OH	3910999999	39	109	METRO19380M19380	Dayton, OH MSA	Miami County	72800	15300	17500	19700	21850	23600	25350	27100	28850	2000	Miami County	Ohio	1
OH	3911199999	39	111	NCNTY39111N39111	Monroe County, OH	Monroe County	52900	13700	15650	17600	19550	21150	22700	24250	25850	9999	Monroe County	Ohio	0
OH	3911399999	39	113	METRO19380M19380	Dayton, OH MSA	Montgomery County	72800	15300	17500	19700	21850	23600	25350	27100	28850	2000	Montgomery County	Ohio	1
OH	3911599999	39	115	NCNTY39115N39115	Morgan County, OH	Morgan County	50100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Morgan County	Ohio	0
OH	3911799999	39	117	METRO18140M18140	Columbus, OH HUD Metro FMR Area	Morrow County	84500	17700	20200	22750	25250	27300	29300	31350	33350	9999	Morrow County	Ohio	1
OH	3911999999	39	119	NCNTY39119N39119	Muskingum County, OH	Muskingum County	62200	13700	15650	17600	19550	21150	22700	24250	25850	9999	Muskingum County	Ohio	0
OH	3912199999	39	121	NCNTY39121N39121	Noble County, OH	Noble County	58600	13700	15650	17600	19550	21150	22700	24250	25850	9999	Noble County	Ohio	0
OH	3912399999	39	123	NCNTY39123N39123	Ottawa County, OH	Ottawa County	73400	15400	17600	19800	22000	23800	25550	27300	29050	9999	Ottawa County	Ohio	0
OH	3912599999	39	125	NCNTY39125N39125	Paulding County, OH	Paulding County	67000	14100	16100	18100	20100	21750	23350	24950	26550	9999	Paulding County	Ohio	0
OH	3912799999	39	127	METRO18140N39127	Perry County, OH HUD Metro FMR Area	Perry County	56600	13700	15650	17600	19550	21150	22700	24250	25850	9999	Perry County	Ohio	1
OH	3912999999	39	129	METRO18140M18140	Columbus, OH HUD Metro FMR Area	Pickaway County	84500	17700	20200	22750	25250	27300	29300	31350	33350	1840	Pickaway County	Ohio	1
OH	3913199999	39	131	NCNTY39131N39131	Pike County, OH	Pike County	57400	13700	15650	17600	19550	21150	22700	24250	25850	9999	Pike County	Ohio	0
OH	3913399999	39	133	METRO10420M10420	Akron, OH MSA	Portage County	76300	16050	18350	20650	22900	24750	26600	28400	30250	80	Portage County	Ohio	1
OH	3913599999	39	135	NCNTY39135N39135	Preble County, OH	Preble County	67100	14150	16150	18150	20150	21800	23400	25000	26600	9999	Preble County	Ohio	0
OH	3913799999	39	137	NCNTY39137N39137	Putnam County, OH	Putnam County	77200	16250	18550	20850	23150	25050	26900	28750	30600	9999	Putnam County	Ohio	0
OH	3913999999	39	139	METRO31900M31900	Mansfield, OH MSA	Richland County	66300	13950	15950	17950	19900	21500	23100	24700	26300	4800	Richland County	Ohio	1
OH	3914199999	39	141	NCNTY39141N39141	Ross County, OH	Ross County	62900	13700	15650	17600	19550	21150	22700	24250	25850	9999	Ross County	Ohio	0
OH	3914399999	39	143	NCNTY39143N39143	Sandusky County, OH	Sandusky County	63500	13700	15650	17600	19550	21150	22700	24250	25850	9999	Sandusky County	Ohio	0
OH	3914599999	39	145	NCNTY39145N39145	Scioto County, OH	Scioto County	59300	13700	15650	17600	19550	21150	22700	24250	25850	9999	Scioto County	Ohio	0
OH	3914799999	39	147	NCNTY39147N39147	Seneca County, OH	Seneca County	63400	13700	15650	17600	19550	21150	22700	24250	25850	9999	Seneca County	Ohio	0
OH	3914999999	39	149	NCNTY39149N39149	Shelby County, OH	Shelby County	74900	15750	18000	20250	22450	24250	26050	27850	29650	9999	Shelby County	Ohio	0
OH	3915199999	39	151	METRO15940M15940	Canton-Massillon, OH MSA	Stark County	69500	14600	16700	18800	20850	22550	24200	25900	27550	1320	Stark County	Ohio	1
OH	3915399999	39	153	METRO10420M10420	Akron, OH MSA	Summit County	76300	16050	18350	20650	22900	24750	26600	28400	30250	80	Summit County	Ohio	1
OH	3915599999	39	155	METRO49660M49660	Youngstown-Warren-Boardman, OH HUD Metro FMR Area	Trumbull County	60700	13700	15650	17600	19550	21150	22700	24250	25850	9320	Trumbull County	Ohio	1
OH	3915799999	39	157	NCNTY39157N39157	Tuscarawas County, OH	Tuscarawas County	65100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Tuscarawas County	Ohio	0
OH	3915999999	39	159	METRO18140N39159	Union County, OH HUD Metro FMR Area	Union County	95600	19800	22600	25450	28250	30550	32800	35050	37300	9999	Union County	Ohio	1
OH	3916199999	39	161	NCNTY39161N39161	Van Wert County, OH	Van Wert County	64500	13700	15650	17600	19550	21150	22700	24250	25850	9999	Van Wert County	Ohio	0
OH	3916399999	39	163	NCNTY39163N39163	Vinton County, OH	Vinton County	55700	13700	15650	17600	19550	21150	22700	24250	25850	9999	Vinton County	Ohio	0
OH	3916599999	39	165	METRO17140M17140	Cincinnati, OH-KY-IN HUD Metro FMR Area	Warren County	86300	18150	20750	23350	25900	28000	30050	32150	34200	1640	Warren County	Ohio	1
OH	3916799999	39	167	NCNTY39167N39167	Washington County, OH	Washington County	63800	13700	15650	17600	19550	21150	22700	24250	25850	6020	Washington County	Ohio	0
OH	3916999999	39	169	NCNTY39169N39169	Wayne County, OH	Wayne County	70300	14800	16900	19000	21100	22800	24500	26200	27900	9999	Wayne County	Ohio	0
OH	3917199999	39	171	NCNTY39171N39171	Williams County, OH	Williams County	61100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Williams County	Ohio	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
OH	3917399999	39	173	METRO45780M45780	Toledo, OH MSA	Wood County	71900	15100	17250	19400	21550	23300	25000	26750	28450	8400	Wood County	Ohio	1
OH	3917599999	39	175	NCNTY39175N39175	Wyandot County, OH	Wyandot County	64000	13700	15650	17600	19550	21150	22700	24250	25850	9999	Wyandot County	Ohio	0
OK	4000199999	40	1	NCNTY40001N40001	Adair County, OK	Adair County	43800	12050	13750	15450	17150	18550	19900	21300	22650	9999	Adair County	Oklahoma	0
OK	4000399999	40	3	NCNTY40003N40003	Alfalfa County, OK	Alfalfa County	71600	15050	17200	19350	21450	23200	24900	26600	28350	9999	Alfalfa County	Oklahoma	0
OK	4000599999	40	5	NCNTY40005N40005	Atoka County, OK	Atoka County	48600	12050	13750	15450	17150	18550	19900	21300	22650	9999	Atoka County	Oklahoma	0
OK	4000799999	40	7	NCNTY40007N40007	Beaver County, OK	Beaver County	64100	13500	15400	17350	19250	20800	22350	23900	25450	9999	Beaver County	Oklahoma	0
OK	4000999999	40	9	NCNTY40009N40009	Beckham County, OK	Beckham County	66200	13900	15900	17900	19850	21450	23050	24650	26250	9999	Beckham County	Oklahoma	0
OK	4001199999	40	11	NCNTY40011N40011	Blaine County, OK	Blaine County	62400	13100	15000	16850	18700	20200	21700	23200	24700	9999	Blaine County	Oklahoma	0
OK	4001399999	40	13	NCNTY40013N40013	Bryan County, OK	Bryan County	55900	12050	13750	15450	17150	18550	19900	21300	22650	9999	Bryan County	Oklahoma	0
OK	4001599999	40	15	NCNTY40015N40015	Caddo County, OK	Caddo County	55900	12050	13750	15450	17150	18550	19900	21300	22650	9999	Caddo County	Oklahoma	0
OK	4001799999	40	17	METRO36420M36420	Oklahoma City, OK HUD Metro FMR Area	Canadian County	74400	15650	17850	20100	22300	24100	25900	27700	29450	5880	Canadian County	Oklahoma	1
OK	4001999999	40	19	NCNTY40019N40019	Carter County, OK	Carter County	62700	13200	15050	16950	18800	20350	21850	23350	24850	9999	Carter County	Oklahoma	0
OK	4002199999	40	21	NCNTY40021N40021	Cherokee County, OK	Cherokee County	54900	12050	13750	15450	17150	18550	19900	21300	22650	9999	Cherokee County	Oklahoma	0
OK	4002399999	40	23	NCNTY40023N40023	Choctaw County, OK	Choctaw County	45300	12050	13750	15450	17150	18550	19900	21300	22650	9999	Choctaw County	Oklahoma	0
OK	4002599999	40	25	NCNTY40025N40025	Cimarron County, OK	Cimarron County	59900	12600	14400	16200	17950	19400	20850	22300	23700	9999	Cimarron County	Oklahoma	0
OK	4002799999	40	27	METRO36420M36420	Oklahoma City, OK HUD Metro FMR Area	Cleveland County	74400	15650	17850	20100	22300	24100	25900	27700	29450	5880	Cleveland County	Oklahoma	1
OK	4002999999	40	29	NCNTY40029N40029	Coal County, OK	Coal County	61100	12850	14700	16550	18350	19850	21300	22800	24250	9999	Coal County	Oklahoma	0
OK	4003199999	40	31	METRO30020M30020	Lawton, OK HUD Metro FMR Area	Comanche County	67100	14150	16150	18150	20150	21800	23400	25000	26600	4200	Comanche County	Oklahoma	1
OK	4003399999	40	33	METRO30020N40033	Cotton County, OK HUD Metro FMR Area	Cotton County	60200	12650	14450	16250	18050	19500	20950	22400	23850	9999	Cotton County	Oklahoma	1
OK	4003599999	40	35	NCNTY40035N40035	Craig County, OK	Craig County	50900	12050	13750	15450	17150	18550	19900	21300	22650	9999	Craig County	Oklahoma	0
OK	4003799999	40	37	METRO46140M46140	Tulsa, OK HUD Metro FMR Area	Creek County	68600	14450	16500	18550	20600	22250	23900	25550	27200	8560	Creek County	Oklahoma	1
OK	4003999999	40	39	NCNTY40039N40039	Custer County, OK	Custer County	60000	12600	14400	16200	18000	19450	20900	22350	23800	9999	Custer County	Oklahoma	0
OK	4004199999	40	41	NCNTY40041N40041	Delaware County, OK	Delaware County	50000	12050	13750	15450	17150	18550	19900	21300	22650	9999	Delaware County	Oklahoma	0
OK	4004399999	40	43	NCNTY40043N40043	Dewey County, OK	Dewey County	65100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Dewey County	Oklahoma	0
OK	4004599999	40	45	NCNTY40045N40045	Ellis County, OK	Ellis County	66700	14500	16600	18650	20700	22400	24050	25700	27350	9999	Ellis County	Oklahoma	0
OK	4004799999	40	47	METRO21420M21420	Enid, OK MSA	Garfield County	65200	13700	15650	17600	19550	21150	22700	24250	25850	2340	Garfield County	Oklahoma	1
OK	4004999999	40	49	NCNTY40049N40049	Garvin County, OK	Garvin County	57000	12050	13750	15450	17150	18550	19900	21300	22650	9999	Garvin County	Oklahoma	0
OK	4005199999	40	51	METRO36420N40051	Grady County, OK HUD Metro FMR Area	Grady County	69800	14700	16800	18900	20950	22650	24350	26000	27700	9999	Grady County	Oklahoma	1
OK	4005399999	40	53	NCNTY40053N40053	Grant County, OK	Grant County	68600	14450	16500	18550	20600	22250	23900	25550	27200	9999	Grant County	Oklahoma	0
OK	4005599999	40	55	NCNTY40055N40055	Greer County, OK	Greer County	55300	12050	13750	15450	17150	18550	19900	21300	22650	9999	Greer County	Oklahoma	0
OK	4005799999	40	57	NCNTY40057N40057	Harmon County, OK	Harmon County	54900	12050	13750	15450	17150	18550	19900	21300	22650	9999	Harmon County	Oklahoma	0
OK	4005999999	40	59	NCNTY40059N40059	Harper County, OK	Harper County	66000	13900	15850	17850	19800	21400	23000	24600	26150	9999	Harper County	Oklahoma	0
OK	4006199999	40	61	NCNTY40061N40061	Haskell County, OK	Haskell County	53600	12050	13750	15450	17150	18550	19900	21300	22650	9999	Haskell County	Oklahoma	0
OK	4006399999	40	63	NCNTY40063N40063	Hughes County, OK	Hughes County	53300	12050	13750	15450	17150	18550	19900	21300	22650	9999	Hughes County	Oklahoma	0
OK	4006599999	40	65	NCNTY40065N40065	Jackson County, OK	Jackson County	57700	12150	13850	15600	17300	18700	20100	21500	22850	9999	Jackson County	Oklahoma	0
OK	4006799999	40	67	NCNTY40067N40067	Jefferson County, OK	Jefferson County	47000	12050	13750	15450	17150	18550	19900	21300	22650	9999	Jefferson County	Oklahoma	0
OK	4006999999	40	69	NCNTY40069N40069	Johnston County, OK	Johnston County	52200	12050	13750	15450	17150	18550	19900	21300	22650	9999	Johnston County	Oklahoma	0
OK	4007199999	40	71	NCNTY40071N40071	Kay County, OK	Kay County	58600	12350	14100	15850	17600	19050	20450	21850	23250	9999	Kay County	Oklahoma	0
OK	4007399999	40	73	NCNTY40073N40073	Kingfisher County, OK	Kingfisher County	75500	15900	18150	20400	22650	24500	26300	28100	29900	9999	Kingfisher County	Oklahoma	0
OK	4007599999	40	75	NCNTY40075N40075	Kiowa County, OK	Kiowa County	53100	12050	13750	15450	17150	18550	19900	21300	22650	9999	Kiowa County	Oklahoma	0
OK	4007799999	40	77	NCNTY40077N40077	Latimer County, OK	Latimer County	53600	12050	13750	15450	17150	18550	19900	21300	22650	9999	Latimer County	Oklahoma	0
OK	4007999999	40	79	METRO22900N40079	Le Flore County, OK HUD Metro FMR Area	Le Flore County	51100	12050	13750	15450	17150	18550	19900	21300	22650	9999	Le Flore County	Oklahoma	1
OK	4008199999	40	81	METRO36420N40081	Lincoln County, OK HUD Metro FMR Area	Lincoln County	61600	12950	14800	16650	18500	20000	21500	22950	24450	9999	Lincoln County	Oklahoma	1
OK	4008399999	40	83	METRO36420M36420	Oklahoma City, OK HUD Metro FMR Area	Logan County	74400	15650	17850	20100	22300	24100	25900	27700	29450	5880	Logan County	Oklahoma	1
OK	4008599999	40	85	NCNTY40085N40085	Love County, OK	Love County	60200	12650	14450	16250	18050	19500	20950	22400	23850	9999	Love County	Oklahoma	0
OK	4008799999	40	87	METRO36420M36420	Oklahoma City, OK HUD Metro FMR Area	McClain County	74400	15650	17850	20100	22300	24100	25900	27700	29450	5880	McClain County	Oklahoma	1
OK	4008999999	40	89	NCNTY40089N40089	McCurtain County, OK	McCurtain County	45900	12050	13750	15450	17150	18550	19900	21300	22650	9999	McCurtain County	Oklahoma	0
OK	4009199999	40	91	NCNTY40091N40091	McIntosh County, OK	McIntosh County	52200	12050	13750	15450	17150	18550	19900	21300	22650	9999	McIntosh County	Oklahoma	0
OK	4009399999	40	93	NCNTY40093N40093	Major County, OK	Major County	68000	14300	16350	18400	20400	22050	23700	25300	26950	9999	Major County	Oklahoma	0
OK	4009599999	40	95	NCNTY40095N40095	Marshall County, OK	Marshall County	56800	12050	13750	15450	17150	18550	19900	21300	22650	9999	Marshall County	Oklahoma	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
OK	4009799999	40	97	NCNTY40097N40097	Mayes County, OK	Mayes County	59200	12450	14200	16000	17750	19200	20600	22050	23450	9999	Mayes County	Oklahoma	0
OK	4009999999	40	99	NCNTY40099N40099	Murray County, OK	Murray County	65300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Murray County	Oklahoma	0
OK	4010199999	40	101	NCNTY40101N40101	Muskogee County, OK	Muskogee County	49400	12050	13750	15450	17150	18550	19900	21300	22650	9999	Muskogee County	Oklahoma	0
OK	4010399999	40	103	NCNTY40103N40103	Noble County, OK	Noble County	68000	14300	16350	18400	20400	22050	23700	25300	26950	9999	Noble County	Oklahoma	0
OK	4010599999	40	105	NCNTY40105N40105	Nowata County, OK	Nowata County	53200	12050	13750	15450	17150	18550	19900	21300	22650	9999	Nowata County	Oklahoma	0
OK	4010799999	40	107	NCNTY40107N40107	Okfuskee County, OK	Okfuskee County	50200	12050	13750	15450	17150	18550	19900	21300	22650	9999	Okfuskee County	Oklahoma	0
OK	4010999999	40	109	METRO36420M36420	Oklahoma City, OK HUD Metro FMR Area	Oklahoma County	74400	15650	17850	20100	22300	24100	25900	27700	29450	5880	Oklahoma County	Oklahoma	1
OK	4011199999	40	111	METRO46140N40111	Okmulgee County, OK HUD Metro FMR Area	Okmulgee County	53300	12050	13750	15450	17150	18550	19900	21300	22650	9999	Okmulgee County	Oklahoma	1
OK	4011399999	40	113	METRO46140M46140	Tulsa, OK HUD Metro FMR Area	Osage County	68600	14450	16500	18550	20600	22250	23900	25550	27200	8560	Osage County	Oklahoma	1
OK	4011599999	40	115	NCNTY40115N40115	Ottawa County, OK	Ottawa County	49900	12050	13750	15450	17150	18550	19900	21300	22650	9999	Ottawa County	Oklahoma	0
OK	4011799999	40	117	METRO46140N40117	Pawnee County, OK HUD Metro FMR Area	Pawnee County	57600	12150	13850	15600	17300	18700	20100	21500	22850	9999	Pawnee County	Oklahoma	1
OK	4011999999	40	119	NCNTY40119N40119	Payne County, OK	Payne County	62200	13100	14950	16800	18650	20150	21650	23150	24650	9999	Payne County	Oklahoma	0
OK	4012199999	40	121	NCNTY40121N40121	Pittsburg County, OK	Pittsburg County	60700	12750	14600	16400	18200	19700	21150	22600	24050	9999	Pittsburg County	Oklahoma	0
OK	4012399999	40	123	NCNTY40123N40123	Pontotoc County, OK	Pontotoc County	62900	13200	15100	17000	18850	20400	21900	23400	24900	9999	Pontotoc County	Oklahoma	0
OK	4012599999	40	125	NCNTY40125N40125	Pottawatomie County, OK	Pottawatomie County	65300	12950	14800	16650	18450	19950	21450	22900	24400	5880	Pottawatomie County	Oklahoma	0
OK	4012799999	40	127	NCNTY40127N40127	Pushmataha County, OK	Pushmataha County	48800	12050	13750	15450	17150	18550	19900	21300	22650	9999	Pushmataha County	Oklahoma	0
OK	4012999999	40	129	NCNTY40129N40129	Roger Mills County, OK	Roger Mills County	66100	13900	15900	17900	19850	21450	23050	24650	26250	9999	Roger Mills County	Oklahoma	0
OK	4013199999	40	131	METRO46140M46140	Tulsa, OK HUD Metro FMR Area	Rogers County	68600	14450	16500	18550	20600	22250	23900	25550	27200	8560	Rogers County	Oklahoma	1
OK	4013399999	40	133	NCNTY40133N40133	Seminole County, OK	Seminole County	50400	12050	13750	15450	17150	18550	19900	21300	22650	9999	Seminole County	Oklahoma	0
OK	4013599999	40	135	METRO22900M22900	Fort Smith, AR-OK HUD Metro FMR Area	Sequoyah County	54200	11400	13000	14650	16250	17550	18850	20150	21450	2720	Sequoyah County	Oklahoma	1
OK	4013799999	40	137	NCNTY40137N40137	Stephens County, OK	Stephens County	61800	13000	14850	16700	18550	20050	21550	23050	24500	9999	Stephens County	Oklahoma	0
OK	4013999999	40	139	NCNTY40139N40139	Texas County, OK	Texas County	64100	13500	15400	17350	19250	20800	22350	23900	25450	9999	Texas County	Oklahoma	0
OK	4014199999	40	141	NCNTY40141N40141	Tillman County, OK	Tillman County	52700	12050	13750	15450	17150	18550	19900	21300	22650	9999	Tillman County	Oklahoma	0
OK	4014399999	40	143	METRO46140M46140	Tulsa, OK HUD Metro FMR Area	Tulsa County	68600	14450	16500	18550	20600	22250	23900	25550	27200	8560	Tulsa County	Oklahoma	1
OK	4014599999	40	145	METRO46140M46140	Tulsa, OK HUD Metro FMR Area	Wagoner County	68600	14450	16500	18550	20600	22250	23900	25550	27200	8560	Wagoner County	Oklahoma	1
OK	4014799999	40	147	NCNTY40147N40147	Washington County, OK	Washington County	65800	13850	15800	17800	19750	21350	22950	24500	26100	9999	Washington County	Oklahoma	0
OK	4014999999	40	149	NCNTY40149N40149	Washita County, OK	Washita County	63800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Washita County	Oklahoma	0
OK	4015199999	40	151	NCNTY40151N40151	Woods County, OK	Woods County	84300	17750	20250	22800	25300	27350	29350	31400	33400	9999	Woods County	Oklahoma	0
OK	4015399999	40	153	NCNTY40153N40153	Woodward County, OK	Woodward County	74900	15750	18000	20250	22450	24250	26050	27850	29650	9999	Woodward County	Oklahoma	0
OR	4100199999	41	1	NCNTY41001N41001	Baker County, OR	Baker County	58100	12900	14750	16600	18400	19900	21350	22850	24300	9999	Baker County	Oregon	0
OR	4100399999	41	3	METRO18700M18700	Corvallis, OR MSA	Benton County	81000	17050	19450	21900	24300	26250	28200	30150	32100	1890	Benton County	Oregon	1
OR	4100599999	41	5	METRO38900M38900	Portland-Vancouver-Hillsboro, OR-WA MSA	Clackamas County	92100	19400	22150	24900	27650	29900	32100	34300	36500	6440	Clackamas County	Oregon	1
OR	4100799999	41	7	NCNTY41007N41007	Clatsop County, OR	Clatsop County	70600	14700	16800	18900	20950	22650	24350	26000	27700	9999	Clatsop County	Oregon	0
OR	4100999999	41	9	METRO38900M38900	Portland-Vancouver-Hillsboro, OR-WA MSA	Columbia County	92100	19400	22150	24900	27650	29900	32100	34300	36500	6440	Columbia County	Oregon	1
OR	4101199999	41	11	NCNTY41011N41011	Coos County, OR	Coos County	53400	12900	14750	16600	18400	19900	21350	22850	24300	9999	Coos County	Oregon	0
OR	4101399999	41	13	NCNTY41013N41013	Crook County, OR	Crook County	60500	12900	14750	16600	18400	19900	21350	22850	24300	9999	Crook County	Oregon	0
OR	4101599999	41	15	NCNTY41015N41015	Curry County, OR	Curry County	59200	12900	14750	16600	18400	19900	21350	22850	24300	9999	Curry County	Oregon	0
OR	4101799999	41	17	METRO13460M13460	Bend-Redmond, OR MSA	Deschutes County	76600	16100	18400	20700	23000	24850	26700	28550	30400	9999	Deschutes County	Oregon	1
OR	4101999999	41	19	NCNTY41019N41019	Douglas County, OR	Douglas County	59600	13150	15000	16900	18750	20250	21750	23250	24750	9999	Douglas County	Oregon	0
OR	4102199999	41	21	NCNTY41021N41021	Gilliam County, OR	Gilliam County	59100	12900	14750	16600	18400	19900	21350	22850	24300	9999	Gilliam County	Oregon	0
OR	4102399999	41	23	NCNTY41023N41023	Grant County, OR	Grant County	60800	12900	14750	16600	18400	19900	21350	22850	24300	9999	Grant County	Oregon	0
OR	4102599999	41	25	NCNTY41025N41025	Harney County, OR	Harney County	53300	12900	14750	16600	18400	19900	21350	22850	24300	9999	Harney County	Oregon	0
OR	4102799999	41	27	NCNTY41027N41027	Hood River County, OR	Hood River County	71700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Hood River County	Oregon	0
OR	4102999999	41	29	METRO32780M32780	Medford, OR MSA	Jackson County	65100	13700	15650	17600	19550	21150	22700	24250	25850	4890	Jackson County	Oregon	1
OR	4103199999	41	31	NCNTY41031N41031	Jefferson County, OR	Jefferson County	60700	12900	14750	16600	18400	19900	21350	22850	24300	9999	Jefferson County	Oregon	0
OR	4103399999	41	33	METRO24420M24420	Grants Pass, OR MSA	Josephine County	57800	13050	14900	16750	18600	20100	21600	23100	24600	9999	Josephine County	Oregon	1

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OR	4103599999	41	35	NCNTY41035N41035	Klamath County, OR	Klamath County	53100	12900	14750	16600	18400	19900	21350	22850	24300	9999	Klamath County	Oregon	0
OR	4103799999	41	37	NCNTY41037N41037	Lake County, OR	Lake County	44700	12900	14750	16600	18400	19900	21350	22850	24300	9999	Lake County	Oregon	0
OR	4103999999	41	39	METRO21660M21660	Eugene-Springfield, OR MSA	Lane County	72200	14700	16800	18900	21000	22700	24400	26050	27750	2400	Lane County	Oregon	1
OR	4104199999	41	41	NCNTY41041N41041	Lincoln County, OR	Lincoln County	55800	12900	14750	16600	18400	19900	21350	22850	24300	9999	Lincoln County	Oregon	0
OR	4104399999	41	43	METRO10540M10540	Albany, OR MSA	Linn County	64500	13550	15500	17450	19350	20900	22450	24000	25550	9999	Linn County	Oregon	1
OR	4104599999	41	45	NCNTY41045N41045	Malheur County, OR	Malheur County	49500	12900	14750	16600	18400	19900	21350	22850	24300	9999	Malheur County	Oregon	0
OR	4104799999	41	47	METRO41420M41420	Salem, OR MSA	Marion County	70600	14850	17000	19100	21200	22900	24600	26300	28000	7080	Marion County	Oregon	1
OR	4104999999	41	49	NCNTY41049N41049	Morrow County, OR	Morrow County	63200	13300	15200	17100	18950	20500	22000	23500	25050	9999	Morrow County	Oregon	0
OR	4105199999	41	51	METRO38900M38900	Portland-Vancouver-Hillsboro, OR-WA MSA	Multnomah County	92100	19400	22150	24900	27650	29900	32100	34300	36500	6440	Multnomah County	Oregon	1
OR	4105399999	41	53	METRO41420M41420	Salem, OR MSA	Polk County	70600	14850	17000	19100	21200	22900	24600	26300	28000	7080	Polk County	Oregon	1
OR	4105599999	41	55	NCNTY41055N41055	Sherman County, OR	Sherman County	69500	14600	16700	18800	20850	22550	24200	25900	27550	9999	Sherman County	Oregon	0
OR	4105799999	41	57	NCNTY41057N41057	Tillamook County, OR	Tillamook County	58500	12900	14750	16600	18400	19900	21350	22850	24300	9999	Tillamook County	Oregon	0
OR	4105999999	41	59	NCNTY41059N41059	Umatilla County, OR	Umatilla County	65300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Umatilla County	Oregon	0
OR	4106199999	41	61	NCNTY41061N41061	Union County, OR	Union County	58900	12900	14750	16600	18400	19900	21350	22850	24300	9999	Union County	Oregon	0
OR	4106399999	41	63	NCNTY41063N41063	Wallowa County, OR	Wallowa County	64400	13400	15300	17200	19100	20650	22200	23700	25250	9999	Wallowa County	Oregon	0
OR	4106599999	41	65	NCNTY41065N41065	Wasco County, OR	Wasco County	58900	14000	16000	18000	20000	21600	23200	24800	26400	9999	Wasco County	Oregon	0
OR	4106799999	41	67	METRO38900M38900	Portland-Vancouver-Hillsboro, OR-WA MSA	Washington County	92100	19400	22150	24900	27650	29900	32100	34300	36500	6440	Washington County	Oregon	1
OR	4106999999	41	69	NCNTY41069N41069	Wheeler County, OR	Wheeler County	53100	12900	14750	16600	18400	19900	21350	22850	24300	9999	Wheeler County	Oregon	0
OR	4107199999	41	71	METRO38900M38900	Portland-Vancouver-Hillsboro, OR-WA MSA	Yamhill County	92100	19400	22150	24900	27650	29900	32100	34300	36500	6440	Yamhill County	Oregon	1
PA	4200199999	42	1	METRO23900M23900	Gettysburg, PA MSA	Adams County	85800	18000	20600	23150	25700	27800	29850	31900	33950	9999	Adams County	Pennsylvania	1
PA	4200399999	42	3	METRO38300M38300	Pittsburgh, PA HUD Metro FMR Area	Allegheny County	83000	17450	19950	22450	24900	26900	28900	30900	32900	6280	Allegheny County	Pennsylvania	1
PA	4200599999	42	5	METRO38300N42005	Armstrong County, PA HUD Metro FMR Area	Armstrong County	64700	13650	15600	17550	19450	21050	22600	24150	25700	9999	Armstrong County	Pennsylvania	1
PA	4200799999	42	7	METRO38300M38300	Pittsburgh, PA HUD Metro FMR Area	Beaver County	83000	17450	19950	22450	24900	26900	28900	30900	32900	6280	Beaver County	Pennsylvania	1
PA	4200999999	42	9	NCNTY42009N42009	Bedford County, PA	Bedford County	61700	13650	15600	17550	19450	21050	22600	24150	25700	9999	Bedford County	Pennsylvania	0
PA	4201199999	42	11	METRO39740M39740	Reading, PA MSA	Berks County	78600	16550	18900	21250	23600	25500	27400	29300	31200	6680	Berks County	Pennsylvania	1
PA	4201399999	42	13	METRO11020M11020	Altoona, PA MSA	Blair County	60000	13650	15600	17550	19450	21050	22600	24150	25700	280	Blair County	Pennsylvania	1
PA	4201599999	42	15	NCNTY42015N42015	Bradford County, PA	Bradford County	67100	14150	16150	18150	20150	21800	23400	25000	26600	9999	Bradford County	Pennsylvania	0
PA	4201799999	42	17	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Bucks County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Bucks County	Pennsylvania	1
PA	4201999999	42	19	METRO38300M38300	Pittsburgh, PA HUD Metro FMR Area	Butler County	83000	17450	19950	22450	24900	26900	28900	30900	32900	6280	Butler County	Pennsylvania	1
PA	4202199999	42	21	METRO27780M27780	Johnstown, PA MSA	Cambria County	62700	13650	15600	17550	19450	21050	22600	24150	25700	3680	Cambria County	Pennsylvania	1
PA	4202399999	42	23	NCNTY42023N42023	Cameron County, PA	Cameron County	58600	13650	15600	17550	19450	21050	22600	24150	25700	9999	Cameron County	Pennsylvania	0
PA	4202599999	42	25	METRO10900M10900	Allentown-Bethlehem-Easton, PA HUD Metro FMR Area	Carbon County	78200	16450	18800	21150	23450	25350	27250	29100	31000	240	Carbon County	Pennsylvania	1
PA	4202799999	42	27	METRO44300M44300	State College, PA MSA	Centre County	88700	18650	21300	23950	26600	28750	30900	33000	35150	8050	Centre County	Pennsylvania	1
PA	4202999999	42	29	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Chester County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Chester County	Pennsylvania	1
PA	4203199999	42	31	NCNTY42031N42031	Clarion County, PA	Clarion County	60700	13650	15600	17550	19450	21050	22600	24150	25700	9999	Clarion County	Pennsylvania	0
PA	4203399999	42	33	NCNTY42033N42033	Clearfield County, PA	Clearfield County	62000	13650	15600	17550	19450	21050	22600	24150	25700	9999	Clearfield County	Pennsylvania	0
PA	4203599999	42	35	NCNTY42035N42035	Clinton County, PA	Clinton County	63800	13650	15600	17550	19450	21050	22600	24150	25700	9999	Clinton County	Pennsylvania	0
PA	4203799999	42	37	METRO14100N42037	Columbia County, PA HUD Metro FMR Area	Columbia County	65800	13850	15800	17800	19750	21350	22950	24500	26100	7560	Columbia County	Pennsylvania	1
PA	4203999999	42	39	NCNTY42039N42039	Crawford County, PA	Crawford County	66000	13900	15850	17850	19800	21400	23000	24600	26150	9999	Crawford County	Pennsylvania	0
PA	4204199999	42	41	METRO25420M25420	Harrisburg-Carlisle, PA MSA	Cumberland County	85000	17850	20400	22950	25500	27550	29600	31650	33700	3240	Cumberland County	Pennsylvania	1
PA	4204399999	42	43	METRO25420M25420	Harrisburg-Carlisle, PA MSA	Dauphin County	85000	17850	20400	22950	25500	27550	29600	31650	33700	3240	Dauphin County	Pennsylvania	1
PA	4204599999	42	45	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Delaware County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Delaware County	Pennsylvania	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
PA	4204799999	42	47	NCNTY42047N42047	Elk County, PA	Elk County	66900	14050	16050	18050	20050	21700	23300	24900	26500	9999	Elk County	Pennsylvania	0
PA	4204999999	42	49	METRO21500M21500	Erie, PA MSA	Erie County	71500	15050	17200	19350	21450	23200	24900	26600	28350	2360	Erie County	Pennsylvania	1
PA	4205199999	42	51	METRO38300M38300	Pittsburgh, PA HUD Metro FMR Area	Fayette County	83000	17450	19950	22450	24900	26900	28900	30900	32900	6280	Fayette County	Pennsylvania	1
PA	4205399999	42	53	NCNTY42053N42053	Forest County, PA	Forest County	47200	13650	15600	17550	19450	21050	22600	24150	25700	9999	Forest County	Pennsylvania	0
PA	4205599999	42	55	METRO16540M16540	Chambersburg-Waynesboro, PA MSA	Franklin County	78300	16450	18800	21150	23500	25400	27300	29150	31050	9999	Franklin County	Pennsylvania	1
PA	4205799999	42	57	NCNTY42057N42057	Fulton County, PA	Fulton County	65300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Fulton County	Pennsylvania	0
PA	4205999999	42	59	NCNTY42059N42059	Greene County, PA	Greene County	66900	14050	16050	18050	20050	21700	23300	24900	26500	9999	Greene County	Pennsylvania	0
PA	4206199999	42	61	NCNTY42061N42061	Huntingdon County, PA	Huntingdon County	61700	13650	15600	17550	19450	21050	22600	24150	25700	9999	Huntingdon County	Pennsylvania	0
PA	4206399999	42	63	NCNTY42063N42063	Indiana County, PA	Indiana County	62500	13650	15600	17550	19450	21050	22600	24150	25700	9999	Indiana County	Pennsylvania	0
PA	4206599999	42	65	NCNTY42065N42065	Jefferson County, PA	Jefferson County	60900	13650	15600	17550	19450	21050	22600	24150	25700	9999	Jefferson County	Pennsylvania	0
PA	4206799999	42	67	NCNTY42067N42067	Juniata County, PA	Juniata County	65300	13750	15700	17650	19600	21200	22750	24350	25900	9999	Juniata County	Pennsylvania	0
PA	4206999999	42	69	METRO42540M42540	Scranton--Wilkes-Barre, PA MSA	Lackawanna County	71700	15050	17200	19350	21500	23250	24950	26700	28400	7560	Lackawanna County	Pennsylvania	1
PA	4207199999	42	71	METRO29540M29540	Lancaster, PA MSA	Lancaster County	79500	16700	19100	21500	23850	25800	27700	29600	31500	4000	Lancaster County	Pennsylvania	1
PA	4207399999	42	73	NCNTY42073N42073	Lawrence County, PA	Lawrence County	69200	14550	16600	18700	20750	22450	24100	25750	27400	9999	Lawrence County	Pennsylvania	0
PA	4207599999	42	75	METRO30140M30140	Lebanon, PA MSA	Lebanon County	77000	16200	18500	20800	23100	24950	26800	28650	30500	3240	Lebanon County	Pennsylvania	1
PA	4207799999	42	77	METRO10900M10900	Allentown-Bethlehem-Easton, PA HUD Metro FMR Area	Lehigh County	78200	16450	18800	21150	23450	25350	27250	29100	31000	240	Lehigh County	Pennsylvania	1
PA	4207999999	42	79	METRO42540M42540	Scranton--Wilkes-Barre, PA MSA	Luzerne County	71700	15050	17200	19350	21500	23250	24950	26700	28400	7560	Luzerne County	Pennsylvania	1
PA	4208199999	42	81	METRO48700M48700	Williamsport, PA MSA	Lycoming County	64800	13650	15600	17550	19450	21050	22600	24150	25700	9140	Lycoming County	Pennsylvania	1
PA	4208399999	42	83	NCNTY42083N42083	McKean County, PA	McKean County	59900	13650	15600	17550	19450	21050	22600	24150	25700	9999	McKean County	Pennsylvania	0
PA	4208599999	42	85	METRO49660MM7610	Sharon, PA HUD Metro FMR Area	Mercer County	66700	14000	16000	18000	20000	21600	23200	24800	26400	7610	Mercer County	Pennsylvania	1
PA	4208799999	42	87	NCNTY42087N42087	Mifflin County, PA	Mifflin County	56200	13650	15600	17550	19450	21050	22600	24150	25700	9999	Mifflin County	Pennsylvania	0
PA	4208999999	42	89	METRO20700M20700	East Stroudsburg, PA MSA	Monroe County	79100	16650	19000	21400	23750	25650	27550	29450	31350	9999	Monroe County	Pennsylvania	1
PA	4209199999	42	91	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Montgomery County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Montgomery County	Pennsylvania	1
PA	4209399999	42	93	METRO14100N42093	Montour County, PA HUD Metro FMR Area	Montour County	76300	16050	18350	20650	22900	24750	26600	28400	30250	9999	Montour County	Pennsylvania	1
PA	4209599999	42	95	METRO10900M10900	Allentown-Bethlehem-Easton, PA HUD Metro FMR Area	Northampton County	78200	16450	18800	21150	23450	25350	27250	29100	31000	240	Northampton County	Pennsylvania	1
PA	4209799999	42	97	NCNTY42097N42097	Northumberland County, PA	Northumberland County	68500	14350	16400	18450	20450	22100	23750	25400	27000	9999	Northumberland County	Pennsylvania	0
PA	4209999999	42	99	METRO25420M25420	Harrisburg-Carlisle, PA MSA	Perry County	85000	17850	20400	22950	25500	27550	29600	31650	33700	3240	Perry County	Pennsylvania	1
PA	4210199999	42	101	METRO37980M37980	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA	Philadelphia County	96600	20300	23200	26100	29000	31350	33650	36000	38300	6160	Philadelphia County	Pennsylvania	1
PA	4210399999	42	103	METRO35620MM5660	Pike County, PA HUD Metro FMR Area	Pike County	79100	16650	19000	21400	23750	25650	27550	29450	31350	5660	Pike County	Pennsylvania	1
PA	4210599999	42	105	NCNTY42105N42105	Potter County, PA	Potter County	57700	13650	15600	17550	19450	21050	22600	24150	25700	9999	Potter County	Pennsylvania	0
PA	4210799999	42	107	NCNTY42107N42107	Schuylkill County, PA	Schuylkill County	66300	13950	15950	17950	19900	21500	23100	24700	26300	9999	Schuylkill County	Pennsylvania	0
PA	4210999999	42	109	NCNTY42109N42109	Snyder County, PA	Snyder County	66900	14050	16050	18050	20050	21700	23300	24900	26500	9999	Snyder County	Pennsylvania	0
PA	4211199999	42	111	NCNTY42111N42111	Somerset County, PA	Somerset County	63500	13650	15600	17550	19450	21050	22600	24150	25700	3680	Somerset County	Pennsylvania	0
PA	4211399999	42	113	NCNTY42113N42113	Sullivan County, PA	Sullivan County	62200	13650	15600	17550	19450	21050	22600	24150	25700	9999	Sullivan County	Pennsylvania	0
PA	4211599999	42	115	NCNTY42115N42115	Susquehanna County, PA	Susquehanna County	66100	13900	15900	17900	19850	21450	23050	24650	26250	9999	Susquehanna County	Pennsylvania	0
PA	4211799999	42	117	NCNTY42117N42117	Tioga County, PA	Tioga County	62000	13650	15600	17550	19450	21050	22600	24150	25700	9999	Tioga County	Pennsylvania	0
PA	4211999999	42	119	NCNTY42119N42119	Union County, PA	Union County	71500	15050	17200	19350	21450	23200	24900	26600	28350	9999	Union County	Pennsylvania	0
PA	4212199999	42	121	NCNTY42121N42121	Venango County, PA	Venango County	61800	13650	15600	17550	19450	21050	22600	24150	25700	9999	Venango County	Pennsylvania	0
PA	4212399999	42	123	NCNTY42123N42123	Warren County, PA	Warren County	62500	13650	15600	17550	19450	21050	22600	24150	25700	9999	Warren County	Pennsylvania	0
PA	4212599999	42	125	METRO38300M38300	Pittsburgh, PA HUD Metro FMR Area	Washington County	83000	17450	19950	22450	24900	26900	28900	30900	32900	6280	Washington County	Pennsylvania	1
PA	4212799999	42	127	NCNTY42127N42127	Wayne County, PA	Wayne County	69000	14500	16600	18650	20700	22400	24050	25700	27350	9999	Wayne County	Pennsylvania	0
PA	4212999999	42	129	METRO38300M38300	Pittsburgh, PA HUD Metro FMR Area	Westmoreland County	83000	17450	19950	22450	24900	26900	28900	30900	32900	6280	Westmoreland County	Pennsylvania	1
PA	4213199999	42	131	METRO42540M42540	Scranton--Wilkes-Barre, PA MSA	Wyoming County	71700	15050	17200	19350	21500	23250	24950	26700	28400	7560	Wyoming County	Pennsylvania	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
PA	4213399999	42	133	METRO49620M49620	York-Hanover, PA MSA	York County	82200	17300	19750	22200	24650	26650	28600	30600	32550	9280	York County	Pennsylvania	1
RI	4400105140	44	1	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Barrington town	Rhode Island	1
RI	4400109280	44	1	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Bristol town	Rhode Island	1
RI	4400173760	44	1	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Bristol County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Warren town	Rhode Island	1
RI	4400318640	44	3	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Kent County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Coventry town	Rhode Island	1
RI	4400322240	44	3	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Kent County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	East Greenwich town	Rhode Island	1
RI	4400374300	44	3	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Kent County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Warwick city	Rhode Island	1
RI	4400377720	44	3	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Kent County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	West Greenwich town	Rhode Island	1
RI	4400378440	44	3	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Kent County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	West Warwick town	Rhode Island	1
RI	4400536820	44	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Newport County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Jamestown town	Rhode Island	1
RI	4400542400	44	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Newport County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Little Compton town	Rhode Island	1
RI	4400545460	44	5	METRO39300N44005	Newport-Middleton-Portsmouth, RI HUD Metro FMR Area	Newport County	100900	21200	24200	27250	30250	32700	35100	37550	39950	9999	Middletown town	Rhode Island	1
RI	4400549960	44	5	METRO39300N44005	Newport-Middleton-Portsmouth, RI HUD Metro FMR Area	Newport County	100900	21200	24200	27250	30250	32700	35100	37550	39950	9999	Newport city	Rhode Island	1
RI	4400557880	44	5	METRO39300N44005	Newport-Middleton-Portsmouth, RI HUD Metro FMR Area	Newport County	100900	21200	24200	27250	30250	32700	35100	37550	39950	9999	Portsmouth town	Rhode Island	1
RI	4400570880	44	5	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Newport County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Tiverton town	Rhode Island	1
RI	4400711800	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Burrillville town	Rhode Island	1
RI	4400714140	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Central Falls city	Rhode Island	1
RI	4400719180	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Cranston city	Rhode Island	1
RI	4400720080	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Cumberland town	Rhode Island	1
RI	4400722960	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	East Providence city	Rhode Island	1
RI	4400727460	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Foster town	Rhode Island	1
RI	4400730340	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Glocester town	Rhode Island	1
RI	4400737720	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Johnston town	Rhode Island	1
RI	4400741500	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Lincoln town	Rhode Island	1
RI	4400751760	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	North Providence town	Rhode Island	1
RI	4400752480	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	North Smithfield town	Rhode Island	1

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RI	4400754640	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Pawtucket city	Rhode Island	1
RI	4400759000	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Providence city	Rhode Island	1
RI	4400764220	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Scituate town	Rhode Island	1
RI	4400766200	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Smithfield town	Rhode Island	1
RI	4400780780	44	7	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Providence County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Woonsocket city	Rhode Island	1
RI	4400914500	44	9	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Washington County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Charlestown town	Rhode Island	1
RI	4400925300	44	9	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Washington County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Exeter town	Rhode Island	1
RI	4400935380	44	9	METRO39300MM5520	Westerly-Hopkinton-New Shoreham, RI HUD Metro FMR Area	Washington County	91200	18800	21450	24150	26800	28950	31100	33250	35400	5520	Hopkinton town	Rhode Island	1
RI	4400948340	44	9	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Washington County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Narragansett town	Rhode Island	1
RI	4400950500	44	9	METRO39300MM5520	Westerly-Hopkinton-New Shoreham, RI HUD Metro FMR Area	Washington County	91200	18800	21450	24150	26800	28950	31100	33250	35400	9999	New Shoreham town	Rhode Island	1
RI	4400951580	44	9	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Washington County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	North Kingstown town	Rhode Island	1
RI	4400961160	44	9	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Washington County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	Richmond town	Rhode Island	1
RI	4400967460	44	9	METRO39300M39300	Providence-Fall River, RI-MA HUD Metro FMR Area	Washington County	87000	18300	20900	23500	26100	28200	30300	32400	34500	6480	South Kingstown town	Rhode Island	1
RI	4400977000	44	9	METRO39300MM5520	Westerly-Hopkinton-New Shoreham, RI HUD Metro FMR Area	Washington County	91200	18800	21450	24150	26800	28950	31100	33250	35400	5520	Westerly town	Rhode Island	1
SC	4500199999	45	1	NCNTY45001N45001	Abbeville County, SC	Abbeville County	49000	11000	12600	14150	15700	17000	18250	19500	20750	9999	Abbeville County	South Carolina	0
SC	4500399999	45	3	METRO12260M12260	Augusta-Richmond County, GA-SC HUD Metro FMR Area	Aiken County	65900	13850	15800	17800	19750	21350	22950	24500	26100	600	Aiken County	South Carolina	1
SC	4500599999	45	5	NCNTY45005N45005	Allendale County, SC	Allendale County	36300	11000	12600	14150	15700	17000	18250	19500	20750	9999	Allendale County	South Carolina	0
SC	4500799999	45	7	METRO24860M11340	Anderson, SC HUD Metro FMR Area	Anderson County	65200	13650	15600	17550	19500	21100	22650	24200	25750	3160	Anderson County	South Carolina	1
SC	4500999999	45	9	NCNTY45009N45009	Bamberg County, SC	Bamberg County	49100	11000	12600	14150	15700	17000	18250	19500	20750	9999	Bamberg County	South Carolina	0
SC	4501199999	45	11	NCNTY45011N45011	Barnwell County, SC	Barnwell County	48200	11000	12600	14150	15700	17000	18250	19500	20750	9999	Barnwell County	South Carolina	0
SC	4501399999	45	13	METRO25940N45013	Beaufort County, SC HUD Metro FMR Area	Beaufort County	81500	17150	19600	22050	24450	26450	28400	30350	32300	9999	Beaufort County	South Carolina	1
SC	4501599999	45	15	METRO16700M16700	Charleston-North Charleston, SC MSA	Berkeley County	81000	17050	19450	21900	24300	26250	28200	30150	32100	1440	Berkeley County	South Carolina	1
SC	4501799999	45	17	METRO17900M17900	Columbia, SC HUD Metro FMR Area	Calhoun County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Calhoun County	South Carolina	1
SC	4501999999	45	19	METRO16700M16700	Charleston-North Charleston, SC MSA	Charleston County	81000	17050	19450	21900	24300	26250	28200	30150	32100	1440	Charleston County	South Carolina	1
SC	4502199999	45	21	NCNTY45021N45021	Cherokee County, SC	Cherokee County	52200	11000	12600	14150	15700	17000	18250	19500	20750	3160	Cherokee County	South Carolina	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
SC	4502399999	45	23	METRO16740N45023	Chester County, SC HUD Metro FMR Area	Chester County	54100	11400	13000	14650	16250	17550	18850	20150	21450	9999	Chester County	South Carolina	1
SC	4502599999	45	25	NCNTY45025N45025	Chesterfield County, SC	Chesterfield County	47900	11000	12600	14150	15700	17000	18250	19500	20750	9999	Chesterfield County	South Carolina	0
SC	4502799999	45	27	NCNTY45027N45027	Clarendon County, SC	Clarendon County	48900	11000	12600	14150	15700	17000	18250	19500	20750	9999	Clarendon County	South Carolina	0
SC	4502999999	45	29	NCNTY45029N45029	Colleton County, SC	Colleton County	43900	11000	12600	14150	15700	17000	18250	19500	20750	9999	Colleton County	South Carolina	0
SC	4503199999	45	31	METRO22500N45031	Darlington County, SC HUD Metro FMR Area	Darlington County	52300	11000	12600	14150	15700	17000	18250	19500	20750	9999	Darlington County	South Carolina	1
SC	4503399999	45	33	NCNTY45033N45033	Dillon County, SC	Dillon County	42400	11000	12600	14150	15700	17000	18250	19500	20750	9999	Dillon County	South Carolina	0
SC	4503599999	45	35	METRO16700M16700	Charleston-North Charleston, SC MSA	Dorchester County	81000	17050	19450	21900	24300	26250	28200	30150	32100	1440	Dorchester County	South Carolina	1
SC	4503799999	45	37	METRO12260M12260	Augusta-Richmond County, GA-SC HUD Metro FMR Area	Edgefield County	65900	13850	15800	17800	19750	21350	22950	24500	26100	600	Edgefield County	South Carolina	1
SC	4503999999	45	39	METRO17900M17900	Columbia, SC HUD Metro FMR Area	Fairfield County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Fairfield County	South Carolina	1
SC	4504199999	45	41	METRO22500M22500	Florence, SC HUD Metro FMR Area	Florence County	56100	12150	13850	15600	17300	18700	20100	21500	22850	2655	Florence County	South Carolina	1
SC	4504399999	45	43	NCNTY45043N45043	Georgetown County, SC	Georgetown County	62500	13150	15000	16900	18750	20250	21750	23250	24750	9999	Georgetown County	South Carolina	0
SC	4504599999	45	45	METRO24860M24860	Greenville-Mauldin-Easley, SC HUD Metro FMR Area	Greenville County	74900	15750	18000	20250	22450	24250	26050	27850	29650	3160	Greenville County	South Carolina	1
SC	4504799999	45	47	NCNTY45047N45047	Greenwood County, SC	Greenwood County	56300	11850	13550	15250	16900	18300	19650	21000	22350	9999	Greenwood County	South Carolina	0
SC	4504999999	45	49	NCNTY45049N45049	Hampton County, SC	Hampton County	46900	11000	12600	14150	15700	17000	18250	19500	20750	9999	Hampton County	South Carolina	0
SC	4505199999	45	51	METRO34820M34820	Myrtle Beach-North Myrtle Beach-Conway, SC HUD Metro FMR Area	Horry County	57400	12250	14000	15750	17450	18850	20250	21650	23050	5330	Horry County	South Carolina	1
SC	4505399999	45	53	METRO25940N45053	Jasper County, SC HUD Metro FMR Area	Jasper County	46000	11000	12600	14150	15700	17000	18250	19500	20750	9999	Jasper County	South Carolina	1
SC	4505599999	45	55	METRO17900N45055	Kershaw County, SC HUD Metro FMR Area	Kershaw County	64400	13500	15400	17350	19250	20800	22350	23900	25450	9999	Kershaw County	South Carolina	1
SC	4505799999	45	57	METRO16740N45057	Lancaster County, SC HUD Metro FMR Area	Lancaster County	79000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lancaster County	South Carolina	1
SC	4505999999	45	59	METRO24860N45059	Laurens County, SC HUD Metro FMR Area	Laurens County	45900	11100	12700	14300	15850	17150	18400	19700	20950	9999	Laurens County	South Carolina	1
SC	4506199999	45	61	NCNTY45061N45061	Lee County, SC	Lee County	43600	11000	12600	14150	15700	17000	18250	19500	20750	9999	Lee County	South Carolina	0
SC	4506399999	45	63	METRO17900M17900	Columbia, SC HUD Metro FMR Area	Lexington County	72600	15300	17450	19650	21800	23550	25300	27050	28800	1760	Lexington County	South Carolina	1
SC	4506599999	45	65	NCNTY45065N45065	McCormick County, SC	McCormick County	54800	11550	13200	14850	16450	17800	19100	20400	21750	9999	McCormick County	South Carolina	0
SC	4506799999	45	67	NCNTY45067N45067	Marion County, SC	Marion County	42100	11000	12600	14150	15700	17000	18250	19500	20750	9999	Marion County	South Carolina	0
SC	4506999999	45	69	NCNTY45069N45069	Marlboro County, SC	Marlboro County	43100	11000	12600	14150	15700	17000	18250	19500	20750	9999	Marlboro County	South Carolina	0
SC	4507199999	45	71	NCNTY45071N45071	Newberry County, SC	Newberry County	51300	11000	12600	14150	15700	17000	18250	19500	20750	9999	Newberry County	South Carolina	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
SC	4507399999	45	73	NCNTY45073N45073	Oconee County, SC	Oconee County	65500	13200	15100	17000	18850	20400	21900	23400	24900	9999	Oconee County	South Carolina	0
SC	4507599999	45	75	NCNTY45075N45075	Orangeburg County, SC	Orangeburg County	52100	11000	12600	14150	15700	17000	18250	19500	20750	9999	Orangeburg County	South Carolina	0
SC	4507799999	45	77	METRO24860M24860	Greenville-Mauldin-Easley, SC HUD Metro FMR Area	Pickens County	74900	15750	18000	20250	22450	24250	26050	27850	29650	3160	Pickens County	South Carolina	1
SC	4507999999	45	79	METRO17900M17900	Columbia, SC HUD Metro FMR Area	Richland County	72600	15300	17450	19650	21800	23550	25300	27050	28800	1760	Richland County	South Carolina	1
SC	4508199999	45	81	METRO17900M17900	Columbia, SC HUD Metro FMR Area	Saluda County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Saluda County	South Carolina	1
SC	4508399999	45	83	METRO43900M43900	Spartanburg, SC HUD Metro FMR Area	Spartanburg County	64700	13600	15550	17500	19400	21000	22550	24100	25650	3160	Spartanburg County	South Carolina	1
SC	4508599999	45	85	METRO44940M44940	Sumter, SC MSA	Sumter County	54700	11500	13150	14800	16400	17750	19050	20350	21650	8140	Sumter County	South Carolina	1
SC	4508799999	45	87	METRO43900N45087	Union County, SC HUD Metro FMR Area	Union County	50400	11000	12600	14150	15700	17000	18250	19500	20750	9999	Union County	South Carolina	1
SC	4508999999	45	89	NCNTY45089N45089	Williamsburg County, SC	Williamsburg County	45700	11000	12600	14150	15700	17000	18250	19500	20750	9999	Williamsburg County	South Carolina	0
SC	4509199999	45	91	METRO16740M16740	Charlotte-Concord-Gastonia, NC-SC HUD Metro FMR Area	York County	83500	17550	20050	22550	25050	27100	29100	31100	33100	1520	York County	South Carolina	1
SD	4600399999	46	3	NCNTY46003N46003	Aurora County, SD	Aurora County	75500	15900	18150	20400	22650	24500	26300	28100	29900	9999	Aurora County	South Dakota	0
SD	4600599999	46	5	NCNTY46005N46005	Beadle County, SD	Beadle County	67100	15400	17600	19800	21950	23750	25500	27250	29000	9999	Beadle County	South Dakota	0
SD	4600799999	46	7	NCNTY46007N46007	Bennett County, SD	Bennett County	50200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Bennett County	South Dakota	0
SD	4600999999	46	9	NCNTY46009N46009	Bon Homme County, SD	Bon Homme County	71200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Bon Homme County	South Dakota	0
SD	4601199999	46	11	NCNTY46011N46011	Brookings County, SD	Brookings County	84600	17250	19700	22150	24600	26600	28550	30550	32500	9999	Brookings County	South Dakota	0
SD	4601399999	46	13	NCNTY46013N46013	Brown County, SD	Brown County	78000	16400	18750	21100	23400	25300	27150	29050	30900	9999	Brown County	South Dakota	0
SD	4601599999	46	15	NCNTY46015N46015	Brule County, SD	Brule County	62700	15400	17600	19800	21950	23750	25500	27250	29000	9999	Brule County	South Dakota	0
SD	4601799999	46	17	NCNTY46017N46017	Buffalo County, SD	Buffalo County	36200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Buffalo County	South Dakota	0
SD	4601999999	46	19	NCNTY46019N46019	Butte County, SD	Butte County	59000	15400	17600	19800	21950	23750	25500	27250	29000	9999	Butte County	South Dakota	0
SD	4602199999	46	21	NCNTY46021N46021	Campbell County, SD	Campbell County	80800	16000	18300	20600	22850	24700	26550	28350	30200	9999	Campbell County	South Dakota	0
SD	4602399999	46	23	NCNTY46023N46023	Charles Mix County, SD	Charles Mix County	62000	15400	17600	19800	21950	23750	25500	27250	29000	9999	Charles Mix County	South Dakota	0
SD	4602599999	46	25	NCNTY46025N46025	Clark County, SD	Clark County	68600	15400	17600	19800	21950	23750	25500	27250	29000	9999	Clark County	South Dakota	0
SD	4602799999	46	27	NCNTY46027N46027	Clay County, SD	Clay County	77600	16000	18300	20600	22850	24700	26550	28350	30200	9999	Clay County	South Dakota	0
SD	4602999999	46	29	NCNTY46029N46029	Codington County, SD	Codington County	75700	15900	18200	20450	22700	24550	26350	28150	30000	9999	Codington County	South Dakota	0
SD	4603199999	46	31	NCNTY46031N46031	Corson County, SD	Corson County	37800	15400	17600	19800	21950	23750	25500	27250	29000	9999	Corson County	South Dakota	0
SD	4603399999	46	33	METRO39660N46033	Custer County, SD HUD Metro FMR Area	Custer County	71300	15400	17600	19800	21950	23750	25500	27250	29000	9999	Custer County	South Dakota	1
SD	4603599999	46	35	NCNTY46035N46035	Davison County, SD	Davison County	68800	15400	17600	19800	21950	23750	25500	27250	29000	9999	Davison County	South Dakota	0
SD	4603799999	46	37	NCNTY46037N46037	Day County, SD	Day County	62300	15400	17600	19800	21950	23750	25500	27250	29000	9999	Day County	South Dakota	0
SD	4603999999	46	39	NCNTY46039N46039	Deuel County, SD	Deuel County	74700	15700	17950	20200	22400	24200	26000	27800	29600	9999	Deuel County	South Dakota	0
SD	4604199999	46	41	NCNTY46041N46041	Dewey County, SD	Dewey County	52700	15400	17600	19800	21950	23750	25500	27250	29000	9999	Dewey County	South Dakota	0
SD	4604399999	46	43	NCNTY46043N46043	Douglas County, SD	Douglas County	70300	15400	17600	19800	21950	23750	25500	27250	29000	9999	Douglas County	South Dakota	0
SD	4604599999	46	45	NCNTY46045N46045	Edmunds County, SD	Edmunds County	81000	17050	19450	21900	24300	26250	28200	30150	32100	9999	Edmunds County	South Dakota	0
SD	4604799999	46	47	NCNTY46047N46047	Fall River County, SD	Fall River County	69900	15400	17600	19800	21950	23750	25500	27250	29000	9999	Fall River County	South Dakota	0
SD	4604999999	46	49	NCNTY46049N46049	Faulk County, SD	Faulk County	83200	17500	20000	22500	24950	26950	28950	30950	32950	9999	Faulk County	South Dakota	0
SD	4605199999	46	51	NCNTY46051N46051	Grant County, SD	Grant County	69300	15400	17600	19800	21950	23750	25500	27250	29000	9999	Grant County	South Dakota	0
SD	4605399999	46	53	NCNTY46053N46053	Gregory County, SD	Gregory County	61700	15400	17600	19800	21950	23750	25500	27250	29000	9999	Gregory County	South Dakota	0
SD	4605599999	46	55	NCNTY46055N46055	Haakon County, SD	Haakon County	47000	15400	17600	19800	21950	23750	25500	27250	29000	9999	Haakon County	South Dakota	0
SD	4605799999	46	57	NCNTY46057N46057	Hamlin County, SD	Hamlin County	71600	15400	17600	19800	21950	23750	25500	27250	29000	9999	Hamlin County	South Dakota	0
SD	4605999999	46	59	NCNTY46059N46059	Hand County, SD	Hand County	77100	16250	18550	20850	23150	25050	26900	28750	30600	9999	Hand County	South Dakota	0
SD	4606199999	46	61	NCNTY46061N46061	Hanson County, SD	Hanson County	79900	16800	19200	21600	23950	25900	27800	29700	31650	9999	Hanson County	South Dakota	0
SD	4606399999	46	63	NCNTY46063N46063	Harding County, SD	Harding County	75100	15800	18050	20300	22550	24400	26200	28000	29800	9999	Harding County	South Dakota	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
SD	4606599999	46	65	NCNTY46065N46065	Hughes County, SD	Hughes County	95800	20150	23000	25900	28750	31050	33350	35650	37950	9999	Hughes County	South Dakota	0
SD	4606799999	46	67	NCNTY46067N46067	Hutchinson County, SD	Hutchinson County	69300	15400	17600	19800	21950	23750	25500	27250	29000	9999	Hutchinson County	South Dakota	0
SD	4606999999	46	69	NCNTY46069N46069	Hyde County, SD	Hyde County	83400	17500	20000	22500	25000	27000	29000	31000	33000	9999	Hyde County	South Dakota	0
SD	4607199999	46	71	NCNTY46071N46071	Jackson County, SD	Jackson County	42700	15400	17600	19800	21950	23750	25500	27250	29000	9999	Jackson County	South Dakota	0
SD	4607399999	46	73	NCNTY46073N46073	Jerauld County, SD	Jerauld County	66100	15400	17600	19800	21950	23750	25500	27250	29000	9999	Jerauld County	South Dakota	0
SD	4607599999	46	75	NCNTY46075N46075	Jones County, SD	Jones County	57700	15400	17600	19800	21950	23750	25500	27250	29000	9999	Jones County	South Dakota	0
SD	4607799999	46	77	NCNTY46077N46077	Kingsbury County, SD	Kingsbury County	72800	15400	17600	19800	21950	23750	25500	27250	29000	9999	Kingsbury County	South Dakota	0
SD	4607999999	46	79	NCNTY46079N46079	Lake County, SD	Lake County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Lake County	South Dakota	0
SD	4608199999	46	81	NCNTY46081N46081	Lawrence County, SD	Lawrence County	74900	15750	18000	20250	22450	24250	26050	27850	29650	9999	Lawrence County	South Dakota	0
SD	4608399999	46	83	METRO43620M43620	Sioux Falls, SD MSA	Lincoln County	86200	18100	20700	23300	25850	27950	30000	32100	34150	7760	Lincoln County	South Dakota	1
SD	4608599999	46	85	NCNTY46085N46085	Lyman County, SD	Lyman County	55700	15400	17600	19800	21950	23750	25500	27250	29000	9999	Lyman County	South Dakota	0
SD	4608799999	46	87	METRO43620M43620	Sioux Falls, SD MSA	McCook County	86200	18100	20700	23300	25850	27950	30000	32100	34150	9999	McCook County	South Dakota	1
SD	4608999999	46	89	NCNTY46089N46089	McPherson County, SD	McPherson County	65500	15400	17600	19800	21950	23750	25500	27250	29000	9999	McPherson County	South Dakota	0
SD	4609199999	46	91	NCNTY46091N46091	Marshall County, SD	Marshall County	74400	15650	17850	20100	22300	24100	25900	27700	29450	9999	Marshall County	South Dakota	0
SD	4609399999	46	93	METRO39660N46093	Meade County, SD HUD Metro FMR Area	Meade County	68500	15400	17600	19800	21950	23750	25500	27250	29000	9999	Meade County	South Dakota	1
SD	4609599999	46	95	NCNTY46095N46095	Mellette County, SD	Mellette County	36900	15400	17600	19800	21950	23750	25500	27250	29000	9999	Mellette County	South Dakota	0
SD	4609799999	46	97	NCNTY46097N46097	Miner County, SD	Miner County	66200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Miner County	South Dakota	0
SD	4609999999	46	99	METRO43620M43620	Sioux Falls, SD MSA	Minnehaha County	86200	18100	20700	23300	25850	27950	30000	32100	34150	7760	Minnehaha County	South Dakota	1
SD	4610199999	46	101	NCNTY46101N46101	Moody County, SD	Moody County	72400	15400	17600	19800	21950	23750	25500	27250	29000	9999	Moody County	South Dakota	0
SD	4610299999	46	102	NCNTY46102N46102	Oglala Lakota County	Oglala Lakota County	29600	15400	17600	19800	21950	23750	25500	27250	29000	9999	Oglala Lakota County	South Dakota	0
SD	4610399999	46	103	METRO39660M39660	Rapid City, SD HUD Metro FMR Area	Pennington County	76000	16000	18250	20550	22800	24650	26450	28300	30100	6660	Pennington County	South Dakota	1
SD	4610599999	46	105	NCNTY46105N46105	Perkins County, SD	Perkins County	69900	15400	17600	19800	21950	23750	25500	27250	29000	9999	Perkins County	South Dakota	0
SD	4610799999	46	107	NCNTY46107N46107	Potter County, SD	Potter County	65100	15400	17600	19800	21950	23750	25500	27250	29000	9999	Potter County	South Dakota	0
SD	4610999999	46	109	NCNTY46109N46109	Roberts County, SD	Roberts County	63800	15400	17600	19800	21950	23750	25500	27250	29000	9999	Roberts County	South Dakota	0
SD	4611199999	46	111	NCNTY46111N46111	Sanborn County, SD	Sanborn County	71800	15400	17600	19800	21950	23750	25500	27250	29000	9999	Sanborn County	South Dakota	0
SD	4611599999	46	115	NCNTY46115N46115	Spink County, SD	Spink County	68900	15400	17600	19800	21950	23750	25500	27250	29000	9999	Spink County	South Dakota	0
SD	4611799999	46	117	NCNTY46117N46117	Stanley County, SD	Stanley County	76100	16000	18300	20600	22850	24700	26550	28350	30200	9999	Stanley County	South Dakota	0
SD	4611999999	46	119	NCNTY46119N46119	Sully County, SD	Sully County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Sully County	South Dakota	0
SD	4612199999	46	121	NCNTY46121N46121	Todd County, SD	Todd County	27200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Todd County	South Dakota	0
SD	4612399999	46	123	NCNTY46123N46123	Tripp County, SD	Tripp County	65500	15400	17600	19800	21950	23750	25500	27250	29000	9999	Tripp County	South Dakota	0
SD	4612599999	46	125	METRO43620M43620	Sioux Falls, SD MSA	Turner County	86200	18100	20700	23300	25850	27950	30000	32100	34150	9999	Turner County	South Dakota	1
SD	4612799999	46	127	METRO43580M43580	Sioux City, IA-NE-SD HUD Metro FMR Area	Union County	75200	15750	18000	20250	22500	24300	26100	27900	29700	9999	Union County	South Dakota	1
SD	4612999999	46	129	NCNTY46129N46129	Walworth County, SD	Walworth County	70200	15400	17600	19800	21950	23750	25500	27250	29000	9999	Walworth County	South Dakota	0
SD	4613599999	46	135	NCNTY46135N46135	Yankton County, SD	Yankton County	68600	15400	17600	19800	21950	23750	25500	27250	29000	9999	Yankton County	South Dakota	0
SD	4613799999	46	137	NCNTY46137N46137	Ziebach County, SD	Ziebach County	35400	15400	17600	19800	21950	23750	25500	27250	29000	9999	Ziebach County	South Dakota	0
TN	4700199999	47	1	METRO28940M28940	Knoxville, TN HUD Metro FMR Area	Anderson County	73900	15550	17750	19950	22150	23950	25700	27500	29250	3840	Anderson County	Tennessee	1
TN	4700399999	47	3	NCNTY47003N47003	Bedford County, TN	Bedford County	55200	11600	13250	14900	16550	17900	19200	20550	21850	9999	Bedford County	Tennessee	0
TN	4700599999	47	5	NCNTY47005N47005	Benton County, TN	Benton County	51100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Benton County	Tennessee	0
TN	4700799999	47	7	NCNTY47007N47007	Bledsoe County, TN	Bledsoe County	52400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Bledsoe County	Tennessee	0
TN	4700999999	47	9	METRO28940M28940	Knoxville, TN HUD Metro FMR Area	Blount County	73900	15550	17750	19950	22150	23950	25700	27500	29250	3840	Blount County	Tennessee	1
TN	4701199999	47	11	METRO17420M17420	Cleveland, TN MSA	Bradley County	61400	12900	14750	16600	18400	19900	21350	22850	24300	9999	Bradley County	Tennessee	1
TN	4701399999	47	13	METRO28940N47013	Campbell County, TN HUD Metro FMR Area	Campbell County	46800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Campbell County	Tennessee	1
TN	4701599999	47	15	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Cannon County	82300	17300	19800	22250	24700	26700	28700	30650	32650	9999	Cannon County	Tennessee	1
TN	4701799999	47	17	NCNTY47017N47017	Carroll County, TN	Carroll County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Carroll County	Tennessee	0
TN	4701999999	47	19	METRO27740M27740	Johnson City, TN MSA	Carter County	57500	12100	13800	15550	17250	18650	20050	21400	22800	3660	Carter County	Tennessee	1
TN	4702199999	47	21	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Cheatham County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Cheatham County	Tennessee	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TN	4702399999	47	23	METRO27180M27180	Jackson, TN HUD Metro FMR Area	Chester County	59600	12550	14350	16150	17900	19350	20800	22200	23650	3580	Chester County	Tennessee	1
TN	4702599999	47	25	NCNTY47025N47025	Claiborne County, TN	Claiborne County	48000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Claiborne County	Tennessee	0
TN	4702799999	47	27	NCNTY47027N47027	Clay County, TN	Clay County	43600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Clay County	Tennessee	0
TN	4702999999	47	29	NCNTY47029N47029	Cocke County, TN	Cocke County	44000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Cocke County	Tennessee	0
TN	4703199999	47	31	NCNTY47031N47031	Coffee County, TN	Coffee County	60800	12800	14600	16450	18250	19750	21200	22650	24100	9999	Coffee County	Tennessee	0
TN	4703399999	47	33	METRO27180N47033	Crockett County, TN HUD Metro FMR Area	Crockett County	53700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Crockett County	Tennessee	1
TN	4703599999	47	35	NCNTY47035N47035	Cumberland County, TN	Cumberland County	52300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Cumberland County	Tennessee	0
TN	4703799999	47	37	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Davidson County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Davidson County	Tennessee	1
TN	4703999999	47	39	NCNTY47039N47039	Decatur County, TN	Decatur County	47600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Decatur County	Tennessee	0
TN	4704199999	47	41	NCNTY47041N47041	DeKalb County, TN	DeKalb County	51700	11550	13200	14850	16450	17800	19100	20400	21750	9999	DeKalb County	Tennessee	0
TN	4704399999	47	43	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Dickson County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Dickson County	Tennessee	1
TN	4704599999	47	45	NCNTY47045N47045	Dyer County, TN	Dyer County	57700	12150	13850	15600	17300	18700	20100	21500	22850	9999	Dyer County	Tennessee	0
TN	4704799999	47	47	METRO32820M32820	Memphis, TN-MS-AR HUD Metro FMR Area	Fayette County	67900	14250	16300	18350	20350	22000	23650	25250	26900	4920	Fayette County	Tennessee	1
TN	4704999999	47	49	NCNTY47049N47049	Fentress County, TN	Fentress County	42000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Fentress County	Tennessee	0
TN	4705199999	47	51	NCNTY47051N47051	Franklin County, TN	Franklin County	57500	12100	13800	15550	17250	18650	20050	21400	22800	9999	Franklin County	Tennessee	0
TN	4705399999	47	53	NCNTY47053N47053	Gibson County, TN	Gibson County	55200	11600	13250	14900	16550	17900	19200	20550	21850	9999	Gibson County	Tennessee	0
TN	4705599999	47	55	NCNTY47055N47055	Giles County, TN	Giles County	57300	12050	13800	15500	17200	18600	20000	21350	22750	9999	Giles County	Tennessee	0
TN	4705799999	47	57	METRO28940M34100	Grainger County, TN HUD Metro FMR Area	Grainger County	52700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Grainger County	Tennessee	1
TN	4705999999	47	59	NCNTY47059N47059	Greene County, TN	Greene County	53400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Greene County	Tennessee	0
TN	4706199999	47	61	NCNTY47061N47061	Grundy County, TN	Grundy County	42300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Grundy County	Tennessee	0
TN	4706399999	47	63	METRO34100M34100	Morristown, TN MSA	Hamblen County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Hamblen County	Tennessee	1
TN	4706599999	47	65	METRO16860M16860	Chattanooga, TN-GA MSA	Hamilton County	72600	15300	17450	19650	21800	23550	25300	27050	28800	1560	Hamilton County	Tennessee	1
TN	4706799999	47	67	NCNTY47067N47067	Hancock County, TN	Hancock County	43400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Hancock County	Tennessee	0
TN	4706999999	47	69	NCNTY47069N47069	Hardeman County, TN	Hardeman County	47900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Hardeman County	Tennessee	0
TN	4707199999	47	71	NCNTY47071N47071	Hardin County, TN	Hardin County	53900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Hardin County	Tennessee	0
TN	4707399999	47	73	METRO28700M28700	Kingsport-Bristol-Bristol, TN-VA MSA	Hawkins County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3660	Hawkins County	Tennessee	1
TN	4707599999	47	75	NCNTY47075N47075	Haywood County, TN	Haywood County	49800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Haywood County	Tennessee	0
TN	4707799999	47	77	NCNTY47077N47077	Henderson County, TN	Henderson County	56000	11800	13450	15150	16800	18150	19500	20850	22200	9999	Henderson County	Tennessee	0
TN	4707999999	47	79	NCNTY47079N47079	Henry County, TN	Henry County	52100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Henry County	Tennessee	0
TN	4708199999	47	81	METRO34980N47081	Hickman County, TN HUD Metro FMR Area	Hickman County	50200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Hickman County	Tennessee	1
TN	4708399999	47	83	NCNTY47083N47083	Houston County, TN	Houston County	52600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Houston County	Tennessee	0
TN	4708599999	47	85	NCNTY47085N47085	Humphreys County, TN	Humphreys County	54500	11550	13200	14850	16450	17800	19100	20400	21750	9999	Humphreys County	Tennessee	0
TN	4708799999	47	87	NCNTY47087N47087	Jackson County, TN	Jackson County	46800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Jackson County	Tennessee	0
TN	4708999999	47	89	METRO34100M34100	Morristown, TN MSA	Jefferson County	55400	11650	13300	14950	16600	17950	19300	20600	21950	9999	Jefferson County	Tennessee	1
TN	4709199999	47	91	NCNTY47091N47091	Johnson County, TN	Johnson County	41100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Johnson County	Tennessee	0
TN	4709399999	47	93	METRO28940M28940	Knoxville, TN HUD Metro FMR Area	Knox County	73900	15550	17750	19950	22150	23950	25700	27500	29250	3840	Knox County	Tennessee	1
TN	4709599999	47	95	NCNTY47095N47095	Lake County, TN	Lake County	50200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Lake County	Tennessee	0
TN	4709799999	47	97	NCNTY47097N47097	Lauderdale County, TN	Lauderdale County	46200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Lauderdale County	Tennessee	0
TN	4709999999	47	99	NCNTY47099N47099	Lawrence County, TN	Lawrence County	52100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Lawrence County	Tennessee	0
TN	4710199999	47	101	NCNTY47101N47101	Lewis County, TN	Lewis County	49200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Lewis County	Tennessee	0
TN	4710399999	47	103	NCNTY47103N47103	Lincoln County, TN	Lincoln County	53800	11550	13200	14850	16450	17800	19100	20400	21750	9999	Lincoln County	Tennessee	0
TN	4710599999	47	105	METRO28940M28940	Knoxville, TN HUD Metro FMR Area	Loudon County	73900	15550	17750	19950	22150	23950	25700	27500	29250	3840	Loudon County	Tennessee	1
TN	4710799999	47	107	NCNTY47107N47107	McMinn County, TN	McMinn County	54600	11550	13200	14850	16450	17800	19100	20400	21750	9999	McMinn County	Tennessee	0
TN	4710999999	47	109	NCNTY47109N47109	McNairy County, TN	McNairy County	48200	11550	13200	14850	16450	17800	19100	20400	21750	9999	McNairy County	Tennessee	0
TN	4711199999	47	111	METRO34980N47111	Macon County, TN HUD Metro FMR Area	Macon County	44600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Macon County	Tennessee	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TN	4711399999	47	113	METRO27180M27180	Jackson, TN HUD Metro FMR Area	Madison County	59600	12550	14350	16150	17900	19350	20800	22200	23650	3580	Madison County	Tennessee	1
TN	4711599999	47	115	METRO16860M16860	Chattanooga, TN-GA MSA	Marion County	72600	15300	17450	19650	21800	23550	25300	27050	28800	1560	Marion County	Tennessee	1
TN	4711799999	47	117	NCNTY47117N47117	Marshall County, TN	Marshall County	58600	12350	14100	15850	17600	19050	20450	21850	23250	9999	Marshall County	Tennessee	0
TN	4711999999	47	119	METRO34980N47119	Maury County, TN HUD Metro FMR Area	Maury County	70800	14700	16800	18900	20950	22650	24350	26000	27700	9999	Maury County	Tennessee	1
TN	4712199999	47	121	NCNTY47121N47121	Meigs County, TN	Meigs County	49400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Meigs County	Tennessee	0
TN	4712399999	47	123	NCNTY47123N47123	Monroe County, TN	Monroe County	48300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Monroe County	Tennessee	0
TN	4712599999	47	125	METRO17300M17300	Clarksville, TN-KY MSA	Montgomery County	68900	13800	15800	17750	19700	21300	22900	24450	26050	1660	Montgomery County	Tennessee	1
TN	4712799999	47	127	NCNTY47127N47127	Moore County, TN	Moore County	65700	13800	15800	17750	19700	21300	22900	24450	26050	9999	Moore County	Tennessee	0
TN	4712999999	47	129	METRO28940N47129	Morgan County, TN HUD Metro FMR Area	Morgan County	52000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Morgan County	Tennessee	1
TN	4713199999	47	131	NCNTY47131N47131	Obion County, TN	Obion County	51400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Obion County	Tennessee	0
TN	4713399999	47	133	NCNTY47133N47133	Overton County, TN	Overton County	48100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Overton County	Tennessee	0
TN	4713599999	47	135	NCNTY47135N47135	Perry County, TN	Perry County	43500	11550	13200	14850	16450	17800	19100	20400	21750	9999	Perry County	Tennessee	0
TN	4713799999	47	137	NCNTY47137N47137	Pickett County, TN	Pickett County	47900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Pickett County	Tennessee	0
TN	4713999999	47	139	METRO17420M17420	Cleveland, TN MSA	Polk County	61400	12900	14750	16600	18400	19900	21350	22850	24300	9999	Polk County	Tennessee	1
TN	4714199999	47	141	NCNTY47141N47141	Putnam County, TN	Putnam County	56500	11900	13600	15300	16950	18350	19700	21050	22400	9999	Putnam County	Tennessee	0
TN	4714399999	47	143	NCNTY47143N47143	Rhea County, TN	Rhea County	54900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Rhea County	Tennessee	0
TN	4714599999	47	145	METRO28940N47145	Roane County, TN HUD Metro FMR Area	Roane County	63300	13300	15200	17100	19000	20550	22050	23600	25100	9999	Roane County	Tennessee	1
TN	4714799999	47	147	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Robertson County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Robertson County	Tennessee	1
TN	4714999999	47	149	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Rutherford County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Rutherford County	Tennessee	1
TN	4715199999	47	151	NCNTY47151N47151	Scott County, TN	Scott County	42500	11550	13200	14850	16450	17800	19100	20400	21750	9999	Scott County	Tennessee	0
TN	4715399999	47	153	METRO16860M16860	Chattanooga, TN-GA MSA	Sequatchie County	72600	15300	17450	19650	21800	23550	25300	27050	28800	9999	Sequatchie County	Tennessee	1
TN	4715599999	47	155	NCNTY47155N47155	Sevier County, TN	Sevier County	58200	12250	14000	15750	17450	18850	20250	21650	23050	3840	Sevier County	Tennessee	0
TN	4715799999	47	157	METRO32820M32820	Memphis, TN-MS-AR HUD Metro FMR Area	Shelby County	67900	14250	16300	18350	20350	22000	23650	25250	26900	4920	Shelby County	Tennessee	1
TN	4715999999	47	159	METRO34980N47159	Smith County, TN HUD Metro FMR Area	Smith County	56200	11800	13500	15200	16850	18200	19550	20900	22250	9999	Smith County	Tennessee	1
TN	4716199999	47	161	NCNTY47161N47161	Stewart County, TN	Stewart County	59300	12500	14250	16050	17800	19250	20650	22100	23500	9999	Stewart County	Tennessee	0
TN	4716399999	47	163	METRO28700M28700	Kingsport-Bristol-Bristol, TN-VA MSA	Sullivan County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3660	Sullivan County	Tennessee	1
TN	4716599999	47	165	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Sumner County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Sumner County	Tennessee	1
TN	4716799999	47	167	METRO32820M32820	Memphis, TN-MS-AR HUD Metro FMR Area	Tipton County	67900	14250	16300	18350	20350	22000	23650	25250	26900	4920	Tipton County	Tennessee	1
TN	4716999999	47	169	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Trousdale County	82300	17300	19800	22250	24700	26700	28700	30650	32650	9999	Trousdale County	Tennessee	1
TN	4717199999	47	171	METRO27740M27740	Johnson City, TN MSA	Unicoi County	57500	12100	13800	15550	17250	18650	20050	21400	22800	3660	Unicoi County	Tennessee	1
TN	4717399999	47	173	METRO28940M28940	Knoxville, TN HUD Metro FMR Area	Union County	73900	15550	17750	19950	22150	23950	25700	27500	29250	3840	Union County	Tennessee	1
TN	4717599999	47	175	NCNTY47175N47175	Van Buren County, TN	Van Buren County	54200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Van Buren County	Tennessee	0
TN	4717799999	47	177	NCNTY47177N47177	Warren County, TN	Warren County	51500	11550	13200	14850	16450	17800	19100	20400	21750	9999	Warren County	Tennessee	0
TN	4717999999	47	179	METRO27740M27740	Johnson City, TN MSA	Washington County	57500	12100	13800	15550	17250	18650	20050	21400	22800	3660	Washington County	Tennessee	1
TN	4718199999	47	181	NCNTY47181N47181	Wayne County, TN	Wayne County	45600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Wayne County	Tennessee	0
TN	4718399999	47	183	NCNTY47183N47183	Weakley County, TN	Weakley County	52300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Weakley County	Tennessee	0
TN	4718599999	47	185	NCNTY47185N47185	White County, TN	White County	48000	11550	13200	14850	16450	17800	19100	20400	21750	9999	White County	Tennessee	0
TN	4718799999	47	187	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Williamson County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Williamson County	Tennessee	1
TN	4718999999	47	189	METRO34980M34980	Nashville-Davidson--Murfreesboro--Franklin, TN HUD Metro FMR Area	Wilson County	82300	17300	19800	22250	24700	26700	28700	30650	32650	5360	Wilson County	Tennessee	1
TX	4800199999	48	1	NCNTY48001N48001	Anderson County, TX	Anderson County	55900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Anderson County	Texas	0
TX	4800399999	48	3	NCNTY48003N48003	Andrews County, TX	Andrews County	84200	17700	20200	22750	25250	27300	29300	31350	33350	9999	Andrews County	Texas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TX	4800599999	48	5	NCNTY48005N48005	Angelina County, TX	Angelina County	57500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Angelina County	Texas	0
TX	4800799999	48	7	METRO18580N48007	Aransas County, TX HUD Metro FMR Area	Aransas County	61500	12950	14800	16650	18450	19950	21450	22900	24400	9999	Aransas County	Texas	1
TX	4800999999	48	9	METRO48660M48660	Wichita Falls, TX MSA	Archer County	64700	13550	15500	17450	19350	20900	22450	24000	25550	9080	Archer County	Texas	1
TX	4801199999	48	11	METRO11100M11100	Amarillo, TX HUD Metro FMR Area	Armstrong County	66900	14350	16400	18450	20450	22100	23750	25400	27000	9999	Armstrong County	Texas	1
TX	4801399999	48	13	METRO41700N48013	Atascosa County, TX HUD Metro FMR Area	Atascosa County	62900	13200	15100	17000	18850	20400	21900	23400	24900	9999	Atascosa County	Texas	1
TX	4801599999	48	15	METRO26420N48015	Austin County, TX HUD Metro FMR Area	Austin County	82200	17200	19650	22100	24550	26550	28500	30450	32450	9999	Austin County	Texas	1
TX	4801799999	48	17	NCNTY48017N48017	Bailey County, TX	Bailey County	53700	12400	14150	15900	17650	19100	20500	21900	23300	9999	Bailey County	Texas	0
TX	4801999999	48	19	METRO41700M41700	San Antonio-New Braunfels, TX HUD Metro FMR Area	Bandera County	72000	15150	17300	19450	21600	23350	25100	26800	28550	9999	Bandera County	Texas	1
TX	4802199999	48	21	METRO12420M12420	Austin-Round Rock, TX MSA	Bastrop County	97600	20550	23450	26400	29300	31650	34000	36350	38700	640	Bastrop County	Texas	1
TX	4802399999	48	23	NCNTY48023N48023	Baylor County, TX	Baylor County	63100	13300	15200	17100	18950	20500	22000	23500	25050	9999	Baylor County	Texas	0
TX	4802599999	48	25	NCNTY48025N48025	Bee County, TX	Bee County	51200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Bee County	Texas	0
TX	4802799999	48	27	METRO28660M28660	Killeen-Temple, TX HUD Metro FMR Area	Bell County	63900	13450	15350	17250	19150	20700	22250	23750	25300	3810	Bell County	Texas	1
TX	4802999999	48	29	METRO41700M41700	San Antonio-New Braunfels, TX HUD Metro FMR Area	Bexar County	72000	15150	17300	19450	21600	23350	25100	26800	28550	7240	Bexar County	Texas	1
TX	4803199999	48	31	NCNTY48031N48031	Blanco County, TX	Blanco County	68800	14600	16650	18750	20800	22500	24150	25800	27500	9999	Blanco County	Texas	0
TX	4803399999	48	33	NCNTY48033N48033	Borden County, TX	Borden County	92600	18550	21200	23850	26500	28650	30750	32900	35000	9999	Borden County	Texas	0
TX	4803599999	48	35	NCNTY48035N48035	Bosque County, TX	Bosque County	59800	12600	14400	16200	17950	19400	20850	22300	23700	9999	Bosque County	Texas	0
TX	4803799999	48	37	METRO45500M45500	Texarkana, TX-Texarkana, AR HUD Metro FMR Area	Bowie County	69800	13300	15200	17100	19000	20550	22050	23600	25100	8360	Bowie County	Texas	1
TX	4803999999	48	39	METRO26420MM1145	Brazoria County, TX HUD Metro FMR Area	Brazoria County	104200	21350	24400	27450	30500	32950	35400	37850	40300	1145	Brazoria County	Texas	1
TX	4804199999	48	41	METRO17780M17780	College Station-Bryan, TX MSA	Brazos County	65600	13800	15800	17750	19700	21300	22900	24450	26050	1260	Brazos County	Texas	1
TX	4804399999	48	43	NCNTY48043N48043	Brewster County, TX	Brewster County	56900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Brewster County	Texas	0
TX	4804599999	48	45	NCNTY48045N48045	Briscoe County, TX	Briscoe County	55400	12400	14150	15900	17650	19100	20500	21900	23300	9999	Briscoe County	Texas	0
TX	4804799999	48	47	NCNTY48047N48047	Brooks County, TX	Brooks County	29800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Brooks County	Texas	0
TX	4804999999	48	49	NCNTY48049N48049	Brown County, TX	Brown County	57900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Brown County	Texas	0
TX	4805199999	48	51	METRO17780M17780	College Station-Bryan, TX MSA	Burleson County	65600	13800	15800	17750	19700	21300	22900	24450	26050	9999	Burleson County	Texas	1
TX	4805399999	48	53	NCNTY48053N48053	Burnet County, TX	Burnet County	70800	14900	17000	19150	21250	22950	24650	26350	28050	9999	Burnet County	Texas	0
TX	4805599999	48	55	METRO12420M12420	Austin-Round Rock, TX MSA	Caldwell County	97600	20550	23450	26400	29300	31650	34000	36350	38700	640	Caldwell County	Texas	1
TX	4805799999	48	57	NCNTY48057N48057	Calhoun County, TX	Calhoun County	72700	15300	17450	19650	21800	23550	25300	27050	28800	9999	Calhoun County	Texas	0
TX	4805999999	48	59	METRO10180M10180	Abilene, TX MSA	Callahan County	64800	13650	15600	17550	19450	21050	22600	24150	25700	9999	Callahan County	Texas	1
TX	4806199999	48	61	METRO15180M15180	Brownsville-Harlingen, TX MSA	Cameron County	47800	12400	14150	15900	17650	19100	20500	21900	23300	1240	Cameron County	Texas	1
TX	4806399999	48	63	NCNTY48063N48063	Camp County, TX	Camp County	54700	12400	14150	15900	17650	19100	20500	21900	23300	9999	Camp County	Texas	0
TX	4806599999	48	65	METRO11100M11100	Amarillo, TX HUD Metro FMR Area	Carson County	66900	14350	16400	18450	20450	22100	23750	25400	27000	9999	Carson County	Texas	1
TX	4806799999	48	67	NCNTY48067N48067	Cass County, TX	Cass County	54500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Cass County	Texas	0
TX	4806999999	48	69	NCNTY48069N48069	Castro County, TX	Castro County	52800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Castro County	Texas	0
TX	4807199999	48	71	METRO26420M26420	Houston-The Woodlands-Sugar Land, TX HUD Metro FMR Area	Chambers County	78800	16600	18950	21300	23650	25550	27450	29350	31250	3360	Chambers County	Texas	1
TX	4807399999	48	73	NCNTY48073N48073	Cherokee County, TX	Cherokee County	55900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Cherokee County	Texas	0
TX	4807599999	48	75	NCNTY48075N48075	Childress County, TX	Childress County	64700	13600	15550	17500	19400	21000	22550	24100	25650	9999	Childress County	Texas	0
TX	4807799999	48	77	METRO48660M48660	Wichita Falls, TX MSA	Clay County	64700	13550	15500	17450	19350	20900	22450	24000	25550	9999	Clay County	Texas	1
TX	4807999999	48	79	NCNTY48079N48079	Cochran County, TX	Cochran County	55500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Cochran County	Texas	0
TX	4808199999	48	81	NCNTY48081N48081	Coke County, TX	Coke County	62400	13100	15000	16850	18700	20200	21700	23200	24700	9999	Coke County	Texas	0
TX	4808399999	48	83	NCNTY48083N48083	Coleman County, TX	Coleman County	49200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Coleman County	Texas	0
TX	4808599999	48	85	METRO19100M19100	Dallas, TX HUD Metro FMR Area	Collin County	86200	18100	20700	23300	25850	27950	30000	32100	34150	1920	Collin County	Texas	1
TX	4808799999	48	87	NCNTY48087N48087	Collingsworth County, TX	Collingsworth County	56200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Collingsworth County	Texas	0
TX	4808999999	48	89	NCNTY48089N48089	Colorado County, TX	Colorado County	69100	13700	15650	17600	19550	21150	22700	24250	25850	9999	Colorado County	Texas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TX	4809199999	48	91	METRO41700M41700	San Antonio-New Braunfels, TX HUD Metro FMR Area	Comal County	72000	15150	17300	19450	21600	23350	25100	26800	28550	7240	Comal County	Texas	1
TX	4809399999	48	93	NCNTY48093N48093	Comanche County, TX	Comanche County	52200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Comanche County	Texas	0
TX	4809599999	48	95	NCNTY48095N48095	Concho County, TX	Concho County	63900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Concho County	Texas	0
TX	4809799999	48	97	NCNTY48097N48097	Cooke County, TX	Cooke County	74200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Cooke County	Texas	0
TX	4809999999	48	99	METRO28660M28660	Killeen-Temple, TX HUD Metro FMR Area	Coryell County	63900	13450	15350	17250	19150	20700	22250	23750	25300	3810	Coryell County	Texas	1
TX	4810199999	48	101	NCNTY48101N48101	Cottle County, TX	Cottle County	49900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Cottle County	Texas	0
TX	4810399999	48	103	NCNTY48103N48103	Crane County, TX	Crane County	79900	16800	19200	21600	23950	25900	27800	29700	31650	9999	Crane County	Texas	0
TX	4810599999	48	105	NCNTY48105N48105	Crockett County, TX	Crockett County	71400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Crockett County	Texas	0
TX	4810799999	48	107	METRO31180M31180	Lubbock, TX HUD Metro FMR Area	Crosby County	69200	14150	16150	18150	20150	21800	23400	25000	26600	9999	Crosby County	Texas	1
TX	4810999999	48	109	NCNTY48109N48109	Culberson County, TX	Culberson County	46100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Culberson County	Texas	0
TX	4811199999	48	111	NCNTY48111N48111	Dallam County, TX	Dallam County	56500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Dallam County	Texas	0
TX	4811399999	48	113	METRO19100M19100	Dallas, TX HUD Metro FMR Area	Dallas County	86200	18100	20700	23300	25850	27950	30000	32100	34150	1920	Dallas County	Texas	1
TX	4811599999	48	115	NCNTY48115N48115	Dawson County, TX	Dawson County	55500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Dawson County	Texas	0
TX	4811799999	48	117	NCNTY48117N48117	Deaf Smith County, TX	Deaf Smith County	63400	13300	15200	17100	19000	20550	22050	23600	25100	9999	Deaf Smith County	Texas	0
TX	4811999999	48	119	NCNTY48119N48119	Delta County, TX	Delta County	56100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Delta County	Texas	0
TX	4812199999	48	121	METRO19100M19100	Dallas, TX HUD Metro FMR Area	Denton County	86200	18100	20700	23300	25850	27950	30000	32100	34150	1920	Denton County	Texas	1
TX	4812399999	48	123	NCNTY48123N48123	DeWitt County, TX	DeWitt County	69700	14650	16750	18850	20900	22600	24250	25950	27600	9999	DeWitt County	Texas	0
TX	4812599999	48	125	NCNTY48125N48125	Dickens County, TX	Dickens County	58800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Dickens County	Texas	0
TX	4812799999	48	127	NCNTY48127N48127	Dimmit County, TX	Dimmit County	40000	12400	14150	15900	17650	19100	20500	21900	23300	9999	Dimmit County	Texas	0
TX	4812999999	48	129	NCNTY48129N48129	Donley County, TX	Donley County	59100	12450	14200	16000	17750	19200	20600	22050	23450	9999	Donley County	Texas	0
TX	4813199999	48	131	NCNTY48131N48131	Duval County, TX	Duval County	43100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Duval County	Texas	0
TX	4813399999	48	133	NCNTY48133N48133	Eastland County, TX	Eastland County	46700	12400	14150	15900	17650	19100	20500	21900	23300	9999	Eastland County	Texas	0
TX	4813599999	48	135	METRO36220M36220	Odessa, TX MSA	Ector County	65500	14800	16900	19000	21100	22800	24500	26200	27900	5800	Ector County	Texas	1
TX	4813799999	48	137	NCNTY48137N48137	Edwards County, TX	Edwards County	67400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Edwards County	Texas	0
TX	4813999999	48	139	METRO19100M19100	Dallas, TX HUD Metro FMR Area	Ellis County	86200	18100	20700	23300	25850	27950	30000	32100	34150	1920	Ellis County	Texas	1
TX	4814199999	48	141	METRO21340M21340	El Paso, TX HUD Metro FMR Area	El Paso County	52500	12400	14150	15900	17650	19100	20500	21900	23300	2320	El Paso County	Texas	1
TX	4814399999	48	143	NCNTY48143N48143	Erath County, TX	Erath County	65400	13300	15200	17100	19000	20550	22050	23600	25100	9999	Erath County	Texas	0
TX	4814599999	48	145	METRO47380N48145	Falls County, TX HUD Metro FMR Area	Falls County	53700	12400	14150	15900	17650	19100	20500	21900	23300	9999	Falls County	Texas	1
TX	4814799999	48	147	NCNTY48147N48147	Fannin County, TX	Fannin County	63200	13300	15200	17100	18950	20500	22000	23500	25050	9999	Fannin County	Texas	0
TX	4814999999	48	149	NCNTY48149N48149	Fayette County, TX	Fayette County	72400	15200	17400	19550	21700	23450	25200	26950	28650	9999	Fayette County	Texas	0
TX	4815199999	48	151	NCNTY48151N48151	Fisher County, TX	Fisher County	66000	13300	15200	17100	19000	20550	22050	23600	25100	9999	Fisher County	Texas	0
TX	4815399999	48	153	NCNTY48153N48153	Floyd County, TX	Floyd County	56100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Floyd County	Texas	0
TX	4815599999	48	155	NCNTY48155N48155	Foard County, TX	Foard County	58200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Foard County	Texas	0
TX	4815799999	48	157	METRO26420M26420	Houston-The Woodlands-Sugar Land, TX HUD Metro FMR Area	Fort Bend County	78800	16600	18950	21300	23650	25550	27450	29350	31250	3360	Fort Bend County	Texas	1
TX	4815999999	48	159	NCNTY48159N48159	Franklin County, TX	Franklin County	64500	13550	15500	17450	19350	20900	22450	24000	25550	9999	Franklin County	Texas	0
TX	4816199999	48	161	NCNTY48161N48161	Freestone County, TX	Freestone County	58700	12400	14150	15900	17650	19100	20500	21900	23300	9999	Freestone County	Texas	0
TX	4816399999	48	163	NCNTY48163N48163	Frio County, TX	Frio County	47900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Frio County	Texas	0
TX	4816599999	48	165	NCNTY48165N48165	Gaines County, TX	Gaines County	66900	14050	16050	18050	20050	21700	23300	24900	26500	9999	Gaines County	Texas	0
TX	4816799999	48	167	METRO26420M26420	Houston-The Woodlands-Sugar Land, TX HUD Metro FMR Area	Galveston County	78800	16600	18950	21300	23650	25550	27450	29350	31250	2920	Galveston County	Texas	1
TX	4816999999	48	169	NCNTY48169N48169	Garza County, TX	Garza County	60100	12650	14450	16250	18050	19500	20950	22400	23850	9999	Garza County	Texas	0
TX	4817199999	48	171	NCNTY48171N48171	Gillespie County, TX	Gillespie County	73700	15500	17700	19900	22100	23900	25650	27450	29200	9999	Gillespie County	Texas	0
TX	4817399999	48	173	NCNTY48173N48173	Glasscock County, TX	Glasscock County	97600	20550	23450	26400	29300	31650	34000	36350	38700	9999	Glasscock County	Texas	0
TX	4817599999	48	175	METRO47020M47020	Victoria, TX MSA	Goliad County	68800	14500	16550	18600	20650	22350	24000	25650	27300	9999	Goliad County	Texas	1
TX	4817799999	48	177	NCNTY48177N48177	Gonzales County, TX	Gonzales County	62000	13050	14900	16750	18600	20100	21600	23100	24600	9999	Gonzales County	Texas	0
TX	4817999999	48	179	NCNTY48179N48179	Gray County, TX	Gray County	63900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Gray County	Texas	0
TX	4818199999	48	181	METRO43300M43300	Sherman-Denison, TX MSA	Grayson County	76000	15300	17500	19700	21850	23600	25350	27100	28850	7640	Grayson County	Texas	1
TX	4818399999	48	183	METRO30980M30980	Longview, TX HUD Metro FMR Area	Gregg County	64800	13300	15200	17100	19000	20550	22050	23600	25100	4420	Gregg County	Texas	1
TX	4818599999	48	185	NCNTY48185N48185	Grimes County, TX	Grimes County	60800	12800	14600	16450	18250	19750	21200	22650	24100	9999	Grimes County	Texas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TX	4818799999	48	187	METRO41700M41700	San Antonio-New Braunfels, TX HUD Metro FMR Area	Guadalupe County	72000	15150	17300	19450	21600	23350	25100	26800	28550	7240	Guadalupe County	Texas	1
TX	4818999999	48	189	NCNTY48189N48189	Hale County, TX	Hale County	55500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Hale County	Texas	0
TX	4819199999	48	191	NCNTY48191N48191	Hall County, TX	Hall County	40000	12400	14150	15900	17650	19100	20500	21900	23300	9999	Hall County	Texas	0
TX	4819399999	48	193	NCNTY48193N48193	Hamilton County, TX	Hamilton County	64300	13550	15450	17400	19300	20850	22400	23950	25500	9999	Hamilton County	Texas	0
TX	4819599999	48	195	NCNTY48195N48195	Hansford County, TX	Hansford County	43600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Hansford County	Texas	0
TX	4819799999	48	197	NCNTY48197N48197	Hardeman County, TX	Hardeman County	55800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Hardeman County	Texas	0
TX	4819999999	48	199	METRO13140M13140	Beaumont-Port Arthur, TX HUD Metro FMR Area	Hardin County	67500	14200	16200	18250	20250	21900	23500	25150	26750	840	Hardin County	Texas	1
TX	4820199999	48	201	METRO26420M26420	Houston-The Woodlands-Sugar Land, TX HUD Metro FMR Area	Harris County	78800	16600	18950	21300	23650	25550	27450	29350	31250	3360	Harris County	Texas	1
TX	4820399999	48	203	NCNTY48203N48203	Harrison County, TX	Harrison County	70200	13300	15200	17100	19000	20550	22050	23600	25100	4420	Harrison County	Texas	0
TX	4820599999	48	205	NCNTY48205N48205	Hartley County, TX	Hartley County	72700	15300	17450	19650	21800	23550	25300	27050	28800	9999	Hartley County	Texas	0
TX	4820799999	48	207	NCNTY48207N48207	Haskell County, TX	Haskell County	55200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Haskell County	Texas	0
TX	4820999999	48	209	METRO12420M12420	Austin-Round Rock, TX MSA	Hays County	97600	20550	23450	26400	29300	31650	34000	36350	38700	640	Hays County	Texas	1
TX	4821199999	48	211	NCNTY48211N48211	Hemphill County, TX	Hemphill County	77000	16200	18500	20800	23100	24950	26800	28650	30500	9999	Hemphill County	Texas	0
TX	4821399999	48	213	NCNTY48213N48213	Henderson County, TX	Henderson County	59200	12450	14200	16000	17750	19200	20600	22050	23450	3286	Henderson County	Texas	0
TX	4821599999	48	215	METRO32580M32580	McAllen-Edinburg-Mission, TX MSA	Hidalgo County	45100	12400	14150	15900	17650	19100	20500	21900	23300	4880	Hidalgo County	Texas	1
TX	4821799999	48	217	NCNTY48217N48217	Hill County, TX	Hill County	61100	12850	14700	16550	18350	19850	21300	22800	24250	9999	Hill County	Texas	0
TX	4821999999	48	219	NCNTY48219N48219	Hockley County, TX	Hockley County	62600	13200	15050	16950	18800	20350	21850	23350	24850	9999	Hockley County	Texas	0
TX	4822199999	48	221	METRO19100N48221	Hood County, TX HUD Metro FMR Area	Hood County	76700	16100	18400	20700	23000	24850	26700	28550	30400	2800	Hood County	Texas	1
TX	4822399999	48	223	NCNTY48223N48223	Hopkins County, TX	Hopkins County	60800	12800	14600	16450	18250	19750	21200	22650	24100	9999	Hopkins County	Texas	0
TX	4822599999	48	225	NCNTY48225N48225	Houston County, TX	Houston County	46800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Houston County	Texas	0
TX	4822799999	48	227	NCNTY48227N48227	Howard County, TX	Howard County	64200	13500	15400	17350	19250	20800	22350	23900	25450	9999	Howard County	Texas	0
TX	4822999999	48	229	METRO21340N48229	Hudspeth County, TX HUD Metro FMR Area	Hudspeth County	52500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Hudspeth County	Texas	1
TX	4823199999	48	231	METRO19100M19100	Dallas, TX HUD Metro FMR Area	Hunt County	86200	18100	20700	23300	25850	27950	30000	32100	34150	1920	Hunt County	Texas	1
TX	4823399999	48	233	NCNTY48233N48233	Hutchinson County, TX	Hutchinson County	65700	13800	15800	17750	19700	21300	22900	24450	26050	9999	Hutchinson County	Texas	0
TX	4823599999	48	235	METRO41660M41660	San Angelo, TX MSA	Irion County	72400	14700	16800	18900	21000	22700	24400	26050	27750	9999	Irion County	Texas	1
TX	4823799999	48	237	NCNTY48237N48237	Jack County, TX	Jack County	72300	14650	16750	18850	20900	22600	24250	25950	27600	9999	Jack County	Texas	0
TX	4823999999	48	239	NCNTY48239N48239	Jackson County, TX	Jackson County	75300	15850	18100	20350	22600	24450	26250	28050	29850	9999	Jackson County	Texas	0
TX	4824199999	48	241	NCNTY48241N48241	Jasper County, TX	Jasper County	61700	12950	14800	16650	18500	20000	21500	22950	24450	9999	Jasper County	Texas	0
TX	4824399999	48	243	NCNTY48243N48243	Jeff Davis County, TX	Jeff Davis County	69700	14650	16750	18850	20900	22600	24250	25950	27600	9999	Jeff Davis County	Texas	0
TX	4824599999	48	245	METRO13140M13140	Beaumont-Port Arthur, TX HUD Metro FMR Area	Jefferson County	67500	14200	16200	18250	20250	21900	23500	25150	26750	840	Jefferson County	Texas	1
TX	4824799999	48	247	NCNTY48247N48247	Jim Hogg County, TX	Jim Hogg County	44800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Jim Hogg County	Texas	0
TX	4824999999	48	249	NCNTY48249N48249	Jim Wells County, TX	Jim Wells County	55400	12400	14150	15900	17650	19100	20500	21900	23300	9999	Jim Wells County	Texas	0
TX	4825199999	48	251	METRO19100MM2800	Fort Worth-Arlington, TX HUD Metro FMR Area	Johnson County	81500	17150	19600	22050	24450	26450	28400	30350	32300	2800	Johnson County	Texas	1
TX	4825399999	48	253	METRO10180M10180	Abilene, TX MSA	Jones County	64800	13650	15600	17550	19450	21050	22600	24150	25700	9999	Jones County	Texas	1
TX	4825599999	48	255	NCNTY48255N48255	Karnes County, TX	Karnes County	68200	14050	16050	18050	20050	21700	23300	24900	26500	9999	Karnes County	Texas	0
TX	4825799999	48	257	METRO19100M19100	Dallas, TX HUD Metro FMR Area	Kaufman County	86200	18100	20700	23300	25850	27950	30000	32100	34150	1920	Kaufman County	Texas	1
TX	4825999999	48	259	METRO41700N48259	Kendall County, TX HUD Metro FMR Area	Kendall County	100800	21200	24200	27250	30250	32700	35100	37550	39950	9999	Kendall County	Texas	1
TX	4826199999	48	261	NCNTY48261N48261	Kenedy County, TX	Kenedy County	58900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Kenedy County	Texas	0
TX	4826399999	48	263	NCNTY48263N48263	Kent County, TX	Kent County	74300	15350	17550	19750	21900	23700	25450	27200	28950	9999	Kent County	Texas	0
TX	4826599999	48	265	NCNTY48265N48265	Kerr County, TX	Kerr County	63300	13300	15200	17100	19000	20550	22050	23600	25100	9999	Kerr County	Texas	0
TX	4826799999	48	267	NCNTY48267N48267	Kimble County, TX	Kimble County	51500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Kimble County	Texas	0
TX	4826999999	48	269	NCNTY48269N48269	King County, TX	King County	86900	18250	20850	23450	26050	28150	30250	32350	34400	9999	King County	Texas	0
TX	4827199999	48	271	NCNTY48271N48271	Kinney County, TX	Kinney County	55300	12400	14150	15900	17650	19100	20500	21900	23300	9999	Kinney County	Texas	0
TX	4827399999	48	273	NCNTY48273N48273	Kleberg County, TX	Kleberg County	57600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Kleberg County	Texas	0
TX	4827599999	48	275	NCNTY48275N48275	Knox County, TX	Knox County	61500	12950	14800	16650	18450	19950	21450	22900	24400	9999	Knox County	Texas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TX	4827799999	48	277	NCNTY48277N48277	Lamar County, TX	Lamar County	56600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Lamar County	Texas	0
TX	4827999999	48	279	NCNTY48279N48279	Lamb County, TX	Lamb County	55800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Lamb County	Texas	0
TX	4828199999	48	281	METRO28660N48281	Lampasas County, TX HUD Metro FMR Area	Lampasas County	70800	14700	16800	18900	20950	22650	24350	26000	27700	9999	Lampasas County	Texas	1
TX	4828399999	48	283	NCNTY48283N48283	La Salle County, TX	La Salle County	50900	12400	14150	15900	17650	19100	20500	21900	23300	9999	La Salle County	Texas	0
TX	4828599999	48	285	NCNTY48285N48285	Lavaca County, TX	Lavaca County	66100	13600	15550	17500	19400	21000	22550	24100	25650	9999	Lavaca County	Texas	0
TX	4828799999	48	287	NCNTY48287N48287	Lee County, TX	Lee County	70200	14750	16850	18950	21050	22750	24450	26150	27800	9999	Lee County	Texas	0
TX	4828999999	48	289	NCNTY48289N48289	Leon County, TX	Leon County	60200	12650	14450	16250	18050	19500	20950	22400	23850	9999	Leon County	Texas	0
TX	4829199999	48	291	METRO26420M26420	Houston-The Woodlands-Sugar Land, TX HUD Metro FMR Area	Liberty County	78800	16600	18950	21300	23650	25550	27450	29350	31250	3360	Liberty County	Texas	1
TX	4829399999	48	293	NCNTY48293N48293	Limestone County, TX	Limestone County	54100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Limestone County	Texas	0
TX	4829599999	48	295	NCNTY48295N48295	Lipscomb County, TX	Lipscomb County	77000	16200	18500	20800	23100	24950	26800	28650	30500	9999	Lipscomb County	Texas	0
TX	4829799999	48	297	NCNTY48297N48297	Live Oak County, TX	Live Oak County	64500	13400	15300	17200	19100	20650	22200	23700	25250	9999	Live Oak County	Texas	0
TX	4829999999	48	299	NCNTY48299N48299	Llano County, TX	Llano County	66600	14000	16000	18000	20000	21600	23200	24800	26400	9999	Llano County	Texas	0
TX	4830199999	48	301	NCNTY48301N48301	Loving County, TX	Loving County	91200	18550	21200	23850	26450	28600	30700	32800	34950	9999	Loving County	Texas	0
TX	4830399999	48	303	METRO31180M31180	Lubbock, TX HUD Metro FMR Area	Lubbock County	69200	14150	16150	18150	20150	21800	23400	25000	26600	4600	Lubbock County	Texas	1
TX	4830599999	48	305	METRO31180N48305	Lynn County, TX HUD Metro FMR Area	Lynn County	57100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Lynn County	Texas	1
TX	4830799999	48	307	NCNTY48307N48307	McCulloch County, TX	McCulloch County	56900	12400	14150	15900	17650	19100	20500	21900	23300	9999	McCulloch County	Texas	0
TX	4830999999	48	309	METRO47380M47380	Waco, TX HUD Metro FMR Area	McLennan County	65700	13800	15800	17750	19700	21300	22900	24450	26050	8800	McLennan County	Texas	1
TX	4831199999	48	311	NCNTY48311N48311	McMullen County, TX	McMullen County	71900	14450	16500	18550	20600	22250	23900	25550	27200	9999	McMullen County	Texas	0
TX	4831399999	48	313	NCNTY48313N48313	Madison County, TX	Madison County	59900	12600	14400	16200	17950	19400	20850	22300	23700	9999	Madison County	Texas	0
TX	4831599999	48	315	NCNTY48315N48315	Marion County, TX	Marion County	53500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Marion County	Texas	0
TX	4831799999	48	317	METRO33260N48317	Martin County, TX HUD Metro FMR Area	Martin County	88000	15600	17800	20050	22250	24050	25850	27600	29400	9999	Martin County	Texas	1
TX	4831999999	48	319	NCNTY48319N48319	Mason County, TX	Mason County	63100	13300	15200	17100	18950	20500	22000	23500	25050	9999	Mason County	Texas	0
TX	4832199999	48	321	NCNTY48321N48321	Matagorda County, TX	Matagorda County	58600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Matagorda County	Texas	0
TX	4832399999	48	323	NCNTY48323N48323	Maverick County, TX	Maverick County	45100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Maverick County	Texas	0
TX	4832599999	48	325	METRO41700N48325	Medina County, TX HUD Metro FMR Area	Medina County	74200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Medina County	Texas	1
TX	4832799999	48	327	NCNTY48327N48327	Menard County, TX	Menard County	53700	12400	14150	15900	17650	19100	20500	21900	23300	9999	Menard County	Texas	0
TX	4832999999	48	329	METRO33260M33260	Midland, TX HUD Metro FMR Area	Midland County	90700	19050	21800	24500	27200	29400	31600	33750	35950	5800	Midland County	Texas	1
TX	4833199999	48	331	NCNTY48331N48331	Milam County, TX	Milam County	58100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Milam County	Texas	0
TX	4833399999	48	333	NCNTY48333N48333	Mills County, TX	Mills County	62500	13150	15000	16900	18750	20250	21750	23250	24750	9999	Mills County	Texas	0
TX	4833599999	48	335	NCNTY48335N48335	Mitchell County, TX	Mitchell County	70800	14900	17000	19150	21250	22950	24650	26350	28050	9999	Mitchell County	Texas	0
TX	4833799999	48	337	NCNTY48337N48337	Montague County, TX	Montague County	55400	12400	14150	15900	17650	19100	20500	21900	23300	9999	Montague County	Texas	0
TX	4833999999	48	339	METRO26420M26420	Houston-The Woodlands-Sugar Land, TX HUD Metro FMR Area	Montgomery County	78800	16600	18950	21300	23650	25550	27450	29350	31250	3360	Montgomery County	Texas	1
TX	4834199999	48	341	NCNTY48341N48341	Moore County, TX	Moore County	61900	13000	14850	16700	18550	20050	21550	23050	24500	9999	Moore County	Texas	0
TX	4834399999	48	343	NCNTY48343N48343	Morris County, TX	Morris County	55000	12400	14150	15900	17650	19100	20500	21900	23300	9999	Morris County	Texas	0
TX	4834599999	48	345	NCNTY48345N48345	Motley County, TX	Motley County	55100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Motley County	Texas	0
TX	4834799999	48	347	NCNTY48347N48347	Nacogdoches County, TX	Nacogdoches County	65100	13300	15200	17100	19000	20550	22050	23600	25100	9999	Nacogdoches County	Texas	0
TX	4834999999	48	349	NCNTY48349N48349	Navarro County, TX	Navarro County	55600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Navarro County	Texas	0
TX	4835199999	48	351	METRO13140N48351	Newton County, TX HUD Metro FMR Area	Newton County	54600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Newton County	Texas	1
TX	4835399999	48	353	NCNTY48353N48353	Nolan County, TX	Nolan County	60400	12700	14500	16300	18100	19550	21000	22450	23900	9999	Nolan County	Texas	0
TX	4835599999	48	355	METRO18580M18580	Corpus Christi, TX HUD Metro FMR Area	Nueces County	66600	14000	16000	18000	20000	21600	23200	24800	26400	1880	Nueces County	Texas	1
TX	4835799999	48	357	NCNTY48357N48357	Ochiltree County, TX	Ochiltree County	62200	13100	14950	16800	18650	20150	21650	23150	24650	9999	Ochiltree County	Texas	0
TX	4835999999	48	359	METRO11100N48359	Oldham County, TX HUD Metro FMR Area	Oldham County	80000	15900	18200	20450	22700	24550	26350	28150	30000	9999	Oldham County	Texas	1
TX	4836199999	48	361	METRO13140M13140	Beaumont-Port Arthur, TX HUD Metro FMR Area	Orange County	67500	14200	16200	18250	20250	21900	23500	25150	26750	840	Orange County	Texas	1
TX	4836399999	48	363	NCNTY48363N48363	Palo Pinto County, TX	Palo Pinto County	57400	12400	14150	15900	17650	19100	20500	21900	23300	9999	Palo Pinto County	Texas	0
TX	4836599999	48	365	NCNTY48365N48365	Panola County, TX	Panola County	61100	12850	14700	16550	18350	19850	21300	22800	24250	9999	Panola County	Texas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TX	4836799999	48	367	METRO19100MM2800	Fort Worth-Arlington, TX HUD Metro FMR Area	Parker County	81500	17150	19600	22050	24450	26450	28400	30350	32300	2800	Parker County	Texas	1
TX	4836999999	48	369	NCNTY48369N48369	Parmer County, TX	Parmer County	57400	12400	14150	15900	17650	19100	20500	21900	23300	9999	Parmer County	Texas	0
TX	4837199999	48	371	NCNTY48371N48371	Pecos County, TX	Pecos County	74200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Pecos County	Texas	0
TX	4837399999	48	373	NCNTY48373N48373	Polk County, TX	Polk County	57600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Polk County	Texas	0
TX	4837599999	48	375	METRO11100M11100	Amarillo, TX HUD Metro FMR Area	Potter County	66900	14350	16400	18450	20450	22100	23750	25400	27000	320	Potter County	Texas	1
TX	4837799999	48	377	NCNTY48377N48377	Presidio County, TX	Presidio County	36900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Presidio County	Texas	0
TX	4837999999	48	379	NCNTY48379N48379	Rains County, TX	Rains County	63900	13450	15350	17250	19150	20700	22250	23750	25300	9999	Rains County	Texas	0
TX	4838199999	48	381	METRO11100M11100	Amarillo, TX HUD Metro FMR Area	Randall County	66900	14350	16400	18450	20450	22100	23750	25400	27000	320	Randall County	Texas	1
TX	4838399999	48	383	NCNTY48383N48383	Reagan County, TX	Reagan County	79700	16750	19150	21550	23900	25850	27750	29650	31550	9999	Reagan County	Texas	0
TX	4838599999	48	385	NCNTY48385N48385	Real County, TX	Real County	53900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Real County	Texas	0
TX	4838799999	48	387	NCNTY48387N48387	Red River County, TX	Red River County	47400	12400	14150	15900	17650	19100	20500	21900	23300	9999	Red River County	Texas	0
TX	4838999999	48	389	NCNTY48389N48389	Reeves County, TX	Reeves County	63300	13300	15200	17100	19000	20550	22050	23600	25100	9999	Reeves County	Texas	0
TX	4839199999	48	391	NCNTY48391N48391	Refugio County, TX	Refugio County	63400	13300	15200	17100	19000	20550	22050	23600	25100	9999	Refugio County	Texas	0
TX	4839399999	48	393	NCNTY48393N48393	Roberts County, TX	Roberts County	95700	20100	23000	25850	28700	31000	33300	35600	37900	9999	Roberts County	Texas	0
TX	4839599999	48	395	METRO17780M17780	College Station-Bryan, TX MSA	Robertson County	65600	13800	15800	17750	19700	21300	22900	24450	26050	9999	Robertson County	Texas	1
TX	4839799999	48	397	METRO19100M19100	Dallas, TX HUD Metro FMR Area	Rockwall County	86200	18100	20700	23300	25850	27950	30000	32100	34150	1920	Rockwall County	Texas	1
TX	4839999999	48	399	NCNTY48399N48399	Runnels County, TX	Runnels County	53800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Runnels County	Texas	0
TX	4840199999	48	401	METRO30980N48401	Rusk County, TX HUD Metro FMR Area	Rusk County	59800	12600	14400	16200	17950	19400	20850	22300	23700	9999	Rusk County	Texas	1
TX	4840399999	48	403	NCNTY48403N48403	Sabine County, TX	Sabine County	44100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Sabine County	Texas	0
TX	4840599999	48	405	NCNTY48405N48405	San Augustine County, TX	San Augustine County	51700	12400	14150	15900	17650	19100	20500	21900	23300	9999	San Augustine County	Texas	0
TX	4840799999	48	407	NCNTY48407N48407	San Jacinto County, TX	San Jacinto County	59600	12550	14350	16150	17900	19350	20800	22200	23650	9999	San Jacinto County	Texas	0
TX	4840999999	48	409	METRO18580M18580	Corpus Christi, TX HUD Metro FMR Area	San Patricio County	66600	14000	16000	18000	20000	21600	23200	24800	26400	1880	San Patricio County	Texas	1
TX	4841199999	48	411	NCNTY48411N48411	San Saba County, TX	San Saba County	55200	12400	14150	15900	17650	19100	20500	21900	23300	9999	San Saba County	Texas	0
TX	4841399999	48	413	NCNTY48413N48413	Schleicher County, TX	Schleicher County	76600	16100	18400	20700	23000	24850	26700	28550	30400	9999	Schleicher County	Texas	0
TX	4841599999	48	415	NCNTY48415N48415	Scurry County, TX	Scurry County	72900	15300	17500	19700	21850	23600	25350	27100	28850	9999	Scurry County	Texas	0
TX	4841799999	48	417	NCNTY48417N48417	Shackelford County, TX	Shackelford County	60500	12750	14550	16350	18150	19650	21100	22550	24000	9999	Shackelford County	Texas	0
TX	4841999999	48	419	NCNTY48419N48419	Shelby County, TX	Shelby County	50000	12400	14150	15900	17650	19100	20500	21900	23300	9999	Shelby County	Texas	0
TX	4842199999	48	421	NCNTY48421N48421	Sherman County, TX	Sherman County	66300	13950	15950	17950	19900	21500	23100	24700	26300	9999	Sherman County	Texas	0
TX	4842399999	48	423	METRO46340M46340	Tyler, TX MSA	Smith County	65600	14050	16050	18050	20050	21700	23300	24900	26500	8640	Smith County	Texas	1
TX	4842599999	48	425	METRO19100N48425	Somervell County, TX HUD Metro FMR Area	Somervell County	62700	13200	15050	16950	18800	20350	21850	23350	24850	9999	Somervell County	Texas	1
TX	4842799999	48	427	NCNTY48427N48427	Starr County, TX	Starr County	32500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Starr County	Texas	0
TX	4842999999	48	429	NCNTY48429N48429	Stephens County, TX	Stephens County	58200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Stephens County	Texas	0
TX	4843199999	48	431	NCNTY48431N48431	Sterling County, TX	Sterling County	72000	15150	17300	19450	21600	23350	25100	26800	28550	9999	Sterling County	Texas	0
TX	4843399999	48	433	NCNTY48433N48433	Stonewall County, TX	Stonewall County	75300	15050	17200	19350	21500	23250	24950	26700	28400	9999	Stonewall County	Texas	0
TX	4843599999	48	435	NCNTY48435N48435	Sutton County, TX	Sutton County	65700	13800	15800	17750	19700	21300	22900	24450	26050	9999	Sutton County	Texas	0
TX	4843799999	48	437	NCNTY48437N48437	Swisher County, TX	Swisher County	49600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Swisher County	Texas	0
TX	4843999999	48	439	METRO19100MM2800	Fort Worth-Arlington, TX HUD Metro FMR Area	Tarrant County	81500	17150	19600	22050	24450	26450	28400	30350	32300	2800	Tarrant County	Texas	1
TX	4844199999	48	441	METRO10180M10180	Abilene, TX MSA	Taylor County	64800	13650	15600	17550	19450	21050	22600	24150	25700	40	Taylor County	Texas	1
TX	4844399999	48	443	NCNTY48443N48443	Terrell County, TX	Terrell County	58900	12400	14150	15900	17650	19100	20500	21900	23300	9999	Terrell County	Texas	0
TX	4844599999	48	445	NCNTY48445N48445	Terry County, TX	Terry County	50200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Terry County	Texas	0
TX	4844799999	48	447	NCNTY48447N48447	Throckmorton County, TX	Throckmorton County	61800	13000	14850	16700	18550	20050	21550	23050	24500	9999	Throckmorton County	Texas	0
TX	4844999999	48	449	NCNTY48449N48449	Titus County, TX	Titus County	54100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Titus County	Texas	0
TX	4845199999	48	451	METRO41660M41660	San Angelo, TX MSA	Tom Green County	72400	14700	16800	18900	21000	22700	24400	26050	27750	7200	Tom Green County	Texas	1
TX	4845399999	48	453	METRO12420M12420	Austin-Round Rock, TX MSA	Travis County	97600	20550	23450	26400	29300	31650	34000	36350	38700	640	Travis County	Texas	1
TX	4845599999	48	455	NCNTY48455N48455	Trinity County, TX	Trinity County	45500	12400	14150	15900	17650	19100	20500	21900	23300	9999	Trinity County	Texas	0
TX	4845799999	48	457	NCNTY48457N48457	Tyler County, TX	Tyler County	63800	13450	15350	17250	19150	20700	22250	23750	25300	9999	Tyler County	Texas	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
TX	4845999999	48	459	METRO30980M30980	Longview, TX HUD Metro FMR Area	Upshur County	64800	13300	15200	17100	19000	20550	22050	23600	25100	4420	Upshur County	Texas	1
TX	4846199999	48	461	NCNTY48461N48461	Upton County, TX	Upton County	71700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Upton County	Texas	0
TX	4846399999	48	463	NCNTY48463N48463	Uvalde County, TX	Uvalde County	56100	12400	14150	15900	17650	19100	20500	21900	23300	9999	Uvalde County	Texas	0
TX	4846599999	48	465	NCNTY48465N48465	Val Verde County, TX	Val Verde County	54600	12400	14150	15900	17650	19100	20500	21900	23300	9999	Val Verde County	Texas	0
TX	4846799999	48	467	NCNTY48467N48467	Van Zandt County, TX	Van Zandt County	62700	13200	15050	16950	18800	20350	21850	23350	24850	9999	Van Zandt County	Texas	0
TX	4846999999	48	469	METRO47020M47020	Victoria, TX MSA	Victoria County	68800	14500	16550	18600	20650	22350	24000	25650	27300	8750	Victoria County	Texas	1
TX	4847199999	48	471	NCNTY48471N48471	Walker County, TX	Walker County	55500	13600	15550	17500	19400	21000	22550	24100	25650	9999	Walker County	Texas	0
TX	4847399999	48	473	METRO26420M26420	Houston-The Woodlands-Sugar Land, TX HUD Metro FMR Area	Waller County	78800	16600	18950	21300	23650	25550	27450	29350	31250	3360	Waller County	Texas	1
TX	4847599999	48	475	NCNTY48475N48475	Ward County, TX	Ward County	80700	15700	17950	20200	22400	24200	26000	27800	29600	9999	Ward County	Texas	0
TX	4847799999	48	477	NCNTY48477N48477	Washington County, TX	Washington County	71000	14950	17050	19200	21300	23050	24750	26450	28150	9999	Washington County	Texas	0
TX	4847999999	48	479	METRO29700M29700	Laredo, TX MSA	Webb County	50600	12400	14150	15900	17650	19100	20500	21900	23300	4080	Webb County	Texas	1
TX	4848199999	48	481	NCNTY48481N48481	Wharton County, TX	Wharton County	61000	12850	14650	16500	18300	19800	21250	22700	24200	9999	Wharton County	Texas	0
TX	4848399999	48	483	NCNTY48483N48483	Wheeler County, TX	Wheeler County	60900	12800	14600	16450	18250	19750	21200	22650	24100	9999	Wheeler County	Texas	0
TX	4848599999	48	485	METRO48660M48660	Wichita Falls, TX MSA	Wichita County	64700	13550	15500	17450	19350	20900	22450	24000	25550	9080	Wichita County	Texas	1
TX	4848799999	48	487	NCNTY48487N48487	Wilbarger County, TX	Wilbarger County	56400	12400	14150	15900	17650	19100	20500	21900	23300	9999	Wilbarger County	Texas	0
TX	4848999999	48	489	NCNTY48489N48489	Willacy County, TX	Willacy County	33300	12400	14150	15900	17650	19100	20500	21900	23300	9999	Willacy County	Texas	0
TX	4849199999	48	491	METRO12420M12420	Austin-Round Rock, TX MSA	Williamson County	97600	20550	23450	26400	29300	31650	34000	36350	38700	640	Williamson County	Texas	1
TX	4849399999	48	493	METRO41700M41700	San Antonio-New Braunfels, TX HUD Metro FMR Area	Wilson County	72000	15150	17300	19450	21600	23350	25100	26800	28550	7240	Wilson County	Texas	1
TX	4849599999	48	495	NCNTY48495N48495	Winkler County, TX	Winkler County	65900	13850	15800	17800	19750	21350	22950	24500	26100	9999	Winkler County	Texas	0
TX	4849799999	48	497	METRO19100N48497	Wise County, TX HUD Metro FMR Area	Wise County	70800	14900	17000	19150	21250	22950	24650	26350	28050	9999	Wise County	Texas	1
TX	4849999999	48	499	NCNTY48499N48499	Wood County, TX	Wood County	59100	12450	14200	16000	17750	19200	20600	22050	23450	9999	Wood County	Texas	0
TX	4850199999	48	501	NCNTY48501N48501	Yoakum County, TX	Yoakum County	73700	15500	17700	19900	22100	23900	25650	27450	29200	9999	Yoakum County	Texas	0
TX	4850399999	48	503	NCNTY48503N48503	Young County, TX	Young County	61600	12950	14800	16650	18500	20000	21500	22950	24450	9999	Young County	Texas	0
TX	4850599999	48	505	NCNTY48505N48505	Zapata County, TX	Zapata County	42200	12400	14150	15900	17650	19100	20500	21900	23300	9999	Zapata County	Texas	0
TX	4850799999	48	507	NCNTY48507N48507	Zavala County, TX	Zavala County	34000	12400	14150	15900	17650	19100	20500	21900	23300	9999	Zavala County	Texas	0
UT	4900199999	49	1	NCNTY49001N49001	Beaver County, UT	Beaver County	67000	15600	17800	20050	22250	24050	25850	27600	29400	9999	Beaver County	Utah	0
UT	4900399999	49	3	METRO36260N49003	Box Elder County, UT HUD Metro FMR Area	Box Elder County	69200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Box Elder County	Utah	1
UT	4900599999	49	5	METRO30860M30860	Logan, UT-ID MSA	Cache County	71000	15600	17800	20050	22250	24050	25850	27600	29400	9999	Cache County	Utah	1
UT	4900799999	49	7	NCNTY49007N49007	Carbon County, UT	Carbon County	63700	15600	17800	20050	22250	24050	25850	27600	29400	9999	Carbon County	Utah	0
UT	4900999999	49	9	NCNTY49009N49009	Daggett County, UT	Daggett County	88600	18100	20650	23250	25800	27900	29950	32000	34100	9999	Daggett County	Utah	0
UT	4901199999	49	11	METRO36260M36260	Ogden-Clearfield, UT HUD Metro FMR Area	Davis County	86300	18150	20750	23350	25900	28000	30050	32150	34200	7160	Davis County	Utah	1
UT	4901399999	49	13	NCNTY49013N49013	Duchesne County, UT	Duchesne County	73700	15600	17800	20050	22250	24050	25850	27600	29400	9999	Duchesne County	Utah	0
UT	4901599999	49	15	NCNTY49015N49015	Emery County, UT	Emery County	69100	15600	17800	20050	22250	24050	25850	27600	29400	9999	Emery County	Utah	0
UT	4901799999	49	17	NCNTY49017N49017	Garfield County, UT	Garfield County	67300	15600	17800	20050	22250	24050	25850	27600	29400	9999	Garfield County	Utah	0
UT	4901999999	49	19	NCNTY49019N49019	Grand County, UT	Grand County	62600	15600	17800	20050	22250	24050	25850	27600	29400	9999	Grand County	Utah	0
UT	4902199999	49	21	NCNTY49021N49021	Iron County, UT	Iron County	59700	15600	17800	20050	22250	24050	25850	27600	29400	9999	Iron County	Utah	0
UT	4902399999	49	23	METRO39340M39340	Provo-Orem, UT MSA	Juab County	80400	16900	19300	21700	24100	26050	28000	29900	31850	9999	Juab County	Utah	1
UT	4902599999	49	25	NCNTY49025N49025	Kane County, UT	Kane County	73700	15600	17800	20050	22250	24050	25850	27600	29400	3739	Kane County	Utah	0
UT	4902799999	49	27	NCNTY49027N49027	Millard County, UT	Millard County	68700	15600	17800	20050	22250	24050	25850	27600	29400	9999	Millard County	Utah	0
UT	4902999999	49	29	METRO36260M36260	Ogden-Clearfield, UT HUD Metro FMR Area	Morgan County	86300	18150	20750	23350	25900	28000	30050	32150	34200	9999	Morgan County	Utah	1
UT	4903199999	49	31	NCNTY49031N49031	Piute County, UT	Piute County	54600	15600	17800	20050	22250	24050	25850	27600	29400	9999	Piute County	Utah	0
UT	4903399999	49	33	NCNTY49033N49033	Rich County, UT	Rich County	67300	15600	17800	20050	22250	24050	25850	27600	29400	9999	Rich County	Utah	0
UT	4903599999	49	35	METRO41620M41620	Salt Lake City, UT HUD Metro FMR Area	Salt Lake County	87900	18450	21100	23750	26350	28500	30600	32700	34800	7160	Salt Lake County	Utah	1
UT	4903799999	49	37	NCNTY49037N49037	San Juan County, UT	San Juan County	53900	15600	17800	20050	22250	24050	25850	27600	29400	9999	San Juan County	Utah	0
UT	4903999999	49	39	NCNTY49039N49039	Sanpete County, UT	Sanpete County	62200	15600	17800	20050	22250	24050	25850	27600	29400	9999	Sanpete County	Utah	0
UT	4904199999	49	41	NCNTY49041N49041	Sevier County, UT	Sevier County	62900	15600	17800	20050	22250	24050	25850	27600	29400	9999	Sevier County	Utah	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
UT	4904399999	49	43	NCNTY49043N49043	Summit County, UT	Summit County	113900	23950	27350	30750	34150	36900	39650	42350	45100	9999	Summit County	Utah	0
UT	4904599999	49	45	METRO41620N49045	Tooele County, UT HUD Metro FMR Area	Tooele County	80800	16800	19200	21600	24000	25950	27850	29800	31700	9999	Tooele County	Utah	1
UT	4904799999	49	47	NCNTY49047N49047	Uintah County, UT	Uintah County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Uintah County	Utah	0
UT	4904999999	49	49	METRO39340M39340	Provo-Orem, UT MSA	Utah County	80400	16900	19300	21700	24100	26050	28000	29900	31850	6520	Utah County	Utah	1
UT	4905199999	49	51	NCNTY49051N49051	Wasatch County, UT	Wasatch County	88400	18550	21200	23850	26500	28650	30750	32900	35000	9999	Wasatch County	Utah	0
UT	4905399999	49	53	METRO41100M41100	St. George, UT MSA	Washington County	70700	15600	17800	20050	22250	24050	25850	27600	29400	9999	Washington County	Utah	1
UT	4905599999	49	55	NCNTY49055N49055	Wayne County, UT	Wayne County	62700	15600	17800	20050	22250	24050	25850	27600	29400	9999	Wayne County	Utah	0
UT	4905799999	49	57	METRO36260M36260	Ogden-Clearfield, UT HUD Metro FMR Area	Weber County	86300	18150	20750	23350	25900	28000	30050	32150	34200	7160	Weber County	Utah	1
VT	5000100325	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Addison town	Vermont	0
VT	5000108575	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Bridport town	Vermont	0
VT	5000109025	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Bristol town	Vermont	0
VT	5000116000	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Cornwall town	Vermont	0
VT	5000126300	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Ferrisburgh town	Vermont	0
VT	5000128600	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Goshen town	Vermont	0
VT	5000129575	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Granville town	Vermont	0
VT	5000131525	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Hancock town	Vermont	0
VT	5000139325	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Leicester town	Vermont	0
VT	5000140075	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Lincoln town	Vermont	0
VT	5000144350	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Middlebury town	Vermont	0
VT	5000145550	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Monkton town	Vermont	0
VT	5000148700	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	New Haven town	Vermont	0
VT	5000153725	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Orwell town	Vermont	0
VT	5000153950	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Panton town	Vermont	0
VT	5000159650	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Ripton town	Vermont	0
VT	5000162575	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Salisbury town	Vermont	0
VT	5000165050	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Shoreham town	Vermont	0
VT	5000170075	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Starksboro town	Vermont	0
VT	5000174650	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Vergennes city	Vermont	0
VT	5000176075	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Waltham town	Vermont	0
VT	5000183275	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Weybridge town	Vermont	0
VT	5000183800	50	1	NCNTY50001N50001	Addison County, VT	Addison County	80700	16950	19400	21800	24200	26150	28100	30050	31950	9999	Whiting town	Vermont	0
VT	5000301450	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Arlington town	Vermont	0
VT	5000304825	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Bennington town	Vermont	0
VT	5000317725	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Dorset town	Vermont	0
VT	5000327962	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Glastenbury town	Vermont	0
VT	5000339025	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Landgrove town	Vermont	0
VT	5000342850	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Manchester town	Vermont	0
VT	5000355000	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Peru town	Vermont	0
VT	5000357025	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Pownal town	Vermont	0
VT	5000358600	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Readsboro town	Vermont	0
VT	5000361000	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Rupert town	Vermont	0
VT	5000362875	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Sandgate town	Vermont	0
VT	5000363175	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Searsburg town	Vermont	0
VT	5000363550	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Shaftsbury town	Vermont	0
VT	5000369775	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Stamford town	Vermont	0
VT	5000371425	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Sunderland town	Vermont	0
VT	5000385075	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Winhall town	Vermont	0
VT	5000385675	50	3	NCNTY50003N50003	Bennington County, VT	Bennington County	69900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Woodford town	Vermont	0
VT	5000502875	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Barnet town	Vermont	0
VT	5000510450	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Burke town	Vermont	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
VT	5000517125	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Danville town	Vermont	0
VT	5000530550	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Groton town	Vermont	0
VT	5000531825	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Hardwick town	Vermont	0
VT	5000537900	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Kirby town	Vermont	0
VT	5000541725	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Lyndon town	Vermont	0
VT	5000547725	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Newark town	Vermont	0
VT	5000554400	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Peacham town	Vermont	0
VT	5000561525	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Ryegate town	Vermont	0
VT	5000562200	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	St. Johnsbury town	Vermont	0
VT	5000564075	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Sheffield town	Vermont	0
VT	5000569925	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Stannard town	Vermont	0
VT	5000571575	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Sutton town	Vermont	0
VT	5000575700	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Walden town	Vermont	0
VT	5000577125	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Waterford town	Vermont	0
VT	5000583500	50	5	NCNTY50005N50005	Caledonia County, VT	Caledonia County	66600	15700	17950	20200	22400	24200	26000	27800	29600	9999	Wheelock town	Vermont	0
VT	5000706550	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Bolton town	Vermont	1
VT	5000710300	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Buels gore	Vermont	1
VT	5000710675	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Burlington city	Vermont	1
VT	5000713300	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Charlotte town	Vermont	1
VT	5000714875	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Colchester town	Vermont	1
VT	5000724175	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Essex town	Vermont	1
VT	5000733475	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Hinesburg town	Vermont	1
VT	5000734600	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Huntington town	Vermont	1
VT	5000736700	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Jericho town	Vermont	1
VT	5000745250	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Milton town	Vermont	1
VT	5000759275	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Richmond town	Vermont	1
VT	5000762050	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	St. George town	Vermont	1
VT	5000764300	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Shelburne town	Vermont	1
VT	5000766175	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	South Burlington city	Vermont	1
VT	5000773975	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Underhill town	Vermont	1
VT	5000780350	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Westford town	Vermont	1
VT	5000784475	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Williston town	Vermont	1
VT	5000785150	50	7	METRO15540M15540	Burlington-South Burlington, VT MSA	Chittenden County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Winooski city	Vermont	1
VT	5000902125	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Averill town	Vermont	0
VT	5000902162	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Avery's gore	Vermont	0
VT	5000906325	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Bloomfield town	Vermont	0
VT	5000908725	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Brighton town	Vermont	0
VT	5000910075	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Brunswick town	Vermont	0
VT	5000911800	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Canaan town	Vermont	0
VT	5000915250	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Concord town	Vermont	0
VT	5000921250	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	East Haven town	Vermont	0
VT	5000925975	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Ferdinand town	Vermont	0
VT	5000929125	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Granby town	Vermont	0
VT	5000930775	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Guildhall town	Vermont	0
VT	5000939700	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Lemington town	Vermont	0
VT	5000939775	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Lewis town	Vermont	0
VT	5000941425	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Lunenburg town	Vermont	0
VT	5000942475	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Maidstone town	Vermont	0
VT	5000952750	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Norton town	Vermont	0
VT	5000975175	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Victory town	Vermont	0
VT	5000976337	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Warner's grant	Vermont	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
VT	5000976562	50	9	NCNTY50009N50009	Essex County, VT	Essex County	51500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Warren's gore	Vermont	0
VT	5001102500	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Bakersfield town	Vermont	1
VT	5001105425	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Berkshire town	Vermont	1
VT	5001124050	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Enosburgh town	Vermont	1
VT	5001124925	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Fairfax town	Vermont	1
VT	5001125225	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Fairfield town	Vermont	1
VT	5001126500	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Fletcher town	Vermont	1
VT	5001127100	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Franklin town	Vermont	1
VT	5001127700	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Georgia town	Vermont	1
VT	5001133025	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Highgate town	Vermont	1
VT	5001145850	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Montgomery town	Vermont	1
VT	5001159125	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Richford town	Vermont	1
VT	5001161675	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	St. Albans city	Vermont	1
VT	5001161750	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	St. Albans town	Vermont	1
VT	5001164600	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Sheldon town	Vermont	1
VT	5001171725	50	11	METRO15540M15540	Burlington-South Burlington, VT MSA	Franklin County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Swanton town	Vermont	1
VT	5001300860	50	13	METRO15540M15540	Burlington-South Burlington, VT MSA	Grand Isle County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Alburgh town	Vermont	1
VT	5001329275	50	13	METRO15540M15540	Burlington-South Burlington, VT MSA	Grand Isle County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	Grand Isle town	Vermont	1
VT	5001335875	50	13	METRO15540M15540	Burlington-South Burlington, VT MSA	Grand Isle County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	Isle La Motte town	Vermont	1
VT	5001350650	50	13	METRO15540M15540	Burlington-South Burlington, VT MSA	Grand Isle County	89700	19250	22000	24750	27500	29700	31900	34100	36300	9999	North Hero town	Vermont	1
VT	5001367000	50	13	METRO15540M15540	Burlington-South Burlington, VT MSA	Grand Isle County	89700	19250	22000	24750	27500	29700	31900	34100	36300	1305	South Hero town	Vermont	1
VT	5001504375	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Belvidere town	Vermont	0
VT	5001511500	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Cambridge town	Vermont	0
VT	5001523500	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Eden town	Vermont	0
VT	5001523725	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Elmore town	Vermont	0
VT	5001535050	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Hyde Park town	Vermont	0
VT	5001537075	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Johnson town	Vermont	0
VT	5001546675	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Morristown town	Vermont	0
VT	5001570525	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Stowe town	Vermont	0
VT	5001577425	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Waterville town	Vermont	0
VT	5001585375	50	15	NCNTY50015N50015	Lamoille County, VT	Lamoille County	71800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Wolcott town	Vermont	0
VT	5001707375	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Bradford town	Vermont	0
VT	5001707600	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Braintree town	Vermont	0
VT	5001709325	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Brookfield town	Vermont	0
VT	5001713525	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Chelsea town	Vermont	0
VT	5001715700	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Corinth town	Vermont	0
VT	5001725675	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Fairlee town	Vermont	0
VT	5001748175	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Newbury town	Vermont	0
VT	5001753425	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Orange town	Vermont	0
VT	5001758075	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Randolph town	Vermont	0
VT	5001770675	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Strafford town	Vermont	0
VT	5001772400	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Thetford town	Vermont	0
VT	5001773075	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Topsham town	Vermont	0
VT	5001773675	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Tunbridge town	Vermont	0
VT	5001774950	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Vershire town	Vermont	0
VT	5001776750	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Washington town	Vermont	0
VT	5001779975	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	West Fairlee town	Vermont	0
VT	5001784175	50	17	NCNTY50017N50017	Orange County, VT	Orange County	74400	15700	17950	20200	22400	24200	26000	27800	29600	9999	Williamstown town	Vermont	0
VT	5001900475	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Albany town	Vermont	0
VT	5001903550	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Barton town	Vermont	0
VT	5001909850	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Brownington town	Vermont	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
VT	5001913150	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Charleston town	Vermont	0
VT	5001916150	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Coventry town	Vermont	0
VT	5001916300	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Craftsbury town	Vermont	0
VT	5001917350	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Derby town	Vermont	0
VT	5001928075	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Glover town	Vermont	0
VT	5001930175	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Greensboro town	Vermont	0
VT	5001933775	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Holland town	Vermont	0
VT	5001935575	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Irasburg town	Vermont	0
VT	5001936325	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Jay town	Vermont	0
VT	5001940525	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Lowell town	Vermont	0
VT	5001946450	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Morgan town	Vermont	0
VT	5001948850	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Newport city	Vermont	0
VT	5001948925	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Newport town	Vermont	0
VT	5001973525	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Troy town	Vermont	0
VT	5001980200	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Westfield town	Vermont	0
VT	5001981700	50	19	NCNTY50019N50019	Orleans County, VT	Orleans County	59800	15700	17950	20200	22400	24200	26000	27800	29600	9999	Westmore town	Vermont	0
VT	5002105200	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Benson town	Vermont	0
VT	5002107750	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Brandon town	Vermont	0
VT	5002111950	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Castleton town	Vermont	0
VT	5002114350	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Chittenden town	Vermont	0
VT	5002114500	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Clarendon town	Vermont	0
VT	5002116825	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Danby town	Vermont	0
VT	5002125375	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Fair Haven town	Vermont	0
VT	5002134450	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Hubbardton town	Vermont	0
VT	5002135425	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Ira town	Vermont	0
VT	5002137685	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Killington town	Vermont	0
VT	5002144125	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Mendon town	Vermont	0
VT	5002144800	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Middletown Springs town	Vermont	0
VT	5002147200	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Mount Holly town	Vermont	0
VT	5002147425	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Mount Tabor town	Vermont	0
VT	5002154250	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Pawlet town	Vermont	0
VT	5002155450	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Pittsfield town	Vermont	0
VT	5002155600	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Pittsford town	Vermont	0
VT	5002156875	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Poultney town	Vermont	0
VT	5002157250	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Proctor town	Vermont	0
VT	5002161225	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Rutland city	Vermont	0
VT	5002161300	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Rutland town	Vermont	0
VT	5002165275	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Shrewsbury town	Vermont	0
VT	5002171050	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Sudbury town	Vermont	0
VT	5002172925	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Tinmouth town	Vermont	0
VT	5002175925	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Wallingford town	Vermont	0
VT	5002177950	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	Wells town	Vermont	0
VT	5002180875	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	West Haven town	Vermont	0
VT	5002182300	50	21	NCNTY50021N50021	Rutland County, VT	Rutland County	71500	15700	17950	20200	22400	24200	26000	27800	29600	9999	West Rutland town	Vermont	0
VT	5002303175	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Barre city	Vermont	0
VT	5002303250	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Barre town	Vermont	0
VT	5002305650	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Berlin town	Vermont	0
VT	5002311125	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Cabot town	Vermont	0
VT	5002311350	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Calais town	Vermont	0
VT	5002318550	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Duxbury town	Vermont	0
VT	5002321925	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	East Montpelier town	Vermont	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
VT	5002325825	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Fayston town	Vermont	0
VT	5002343600	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Marshfield town	Vermont	0
VT	5002344500	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Middlesex town	Vermont	0
VT	5002346000	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Montpelier city	Vermont	0
VT	5002346225	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Moretown town	Vermont	0
VT	5002350275	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Northfield town	Vermont	0
VT	5002355825	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Plainfield town	Vermont	0
VT	5002360625	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Roxbury town	Vermont	0
VT	5002375325	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Waitsfield town	Vermont	0
VT	5002376525	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Warren town	Vermont	0
VT	5002376975	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Waterbury town	Vermont	0
VT	5002385525	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Woodbury town	Vermont	0
VT	5002386125	50	23	NCNTY50023N50023	Washington County, VT	Washington County	80300	16900	19300	21700	24100	26050	28000	29900	31850	9999	Worcester town	Vermont	0
VT	5002501900	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Athens town	Vermont	0
VT	5002507900	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Brattleboro town	Vermont	0
VT	5002509475	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Brookline town	Vermont	0
VT	5002517875	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Dover town	Vermont	0
VT	5002518325	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Dummerston town	Vermont	0
VT	5002528900	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Grafton town	Vermont	0
VT	5002530925	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Guilford town	Vermont	0
VT	5002531150	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Halifax town	Vermont	0
VT	5002536175	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Jamaica town	Vermont	0
VT	5002540225	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Londonderry town	Vermont	0
VT	5002543375	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Marlboro town	Vermont	0
VT	5002548400	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Newfane town	Vermont	0
VT	5002557700	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Putney town	Vermont	0
VT	5002560250	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Rockingham town	Vermont	0
VT	5002565762	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Somerset town	Vermont	0
VT	5002570750	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Stratton town	Vermont	0
VT	5002573300	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Townshend town	Vermont	0
VT	5002574800	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Vernon town	Vermont	0
VT	5002576225	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Wardsboro town	Vermont	0
VT	5002581400	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Westminster town	Vermont	0
VT	5002583950	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Whitingham town	Vermont	0
VT	5002584700	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Wilmington town	Vermont	0
VT	5002584850	50	25	NCNTY50025N50025	Windham County, VT	Windham County	70900	15700	17950	20200	22400	24200	26000	27800	29600	9999	Windham town	Vermont	0
VT	5002701300	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Andover town	Vermont	0
VT	5002702575	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Baltimore town	Vermont	0
VT	5002702725	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Barnard town	Vermont	0
VT	5002705800	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Bethel town	Vermont	0
VT	5002708275	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Bridgewater town	Vermont	0
VT	5002712250	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Cavendish town	Vermont	0
VT	5002713675	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Chester town	Vermont	0
VT	5002732275	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Hartford town	Vermont	0
VT	5002732425	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Hartland town	Vermont	0
VT	5002741275	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Ludlow town	Vermont	0
VT	5002752900	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Norwich town	Vermont	0
VT	5002756050	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Plymouth town	Vermont	0
VT	5002756350	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Pomfret town	Vermont	0
VT	5002758375	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Reading town	Vermont	0
VT	5002760100	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Rochester town	Vermont	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
VT	5002760850	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Royalton town	Vermont	0
VT	5002763775	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Sharon town	Vermont	0
VT	5002769550	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Springfield town	Vermont	0
VT	5002770375	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Stockbridge town	Vermont	0
VT	5002777500	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Weathersfield town	Vermont	0
VT	5002782000	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Weston town	Vermont	0
VT	5002783050	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	West Windsor town	Vermont	0
VT	5002784925	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Windsor town	Vermont	0
VT	5002785975	50	27	NCNTY50027N50027	Windsor County, VT	Windsor County	79300	16700	19050	21450	23800	25750	27650	29550	31450	9999	Woodstock town	Vermont	0
VA	5100199999	51	1	NCNTY51001N51001	Accomack County, VA	Accomack County	56400	12700	14500	16300	18100	19550	21000	22450	23900	9999	Accomack County	Virginia	0
VA	5100399999	51	3	METRO16820M16820	Charlottesville, VA HUD Metro FMR Area	Albemarle County	93900	19750	22550	25350	28150	30450	32700	34950	37200	1540	Albemarle County	Virginia	1
VA	5100599999	51	5	NCNTY51005N51005	Alleghany County-Clifton Forge city-Covington city, VA HUD Nonmet	Alleghany County	60700	12750	14600	16400	18200	19700	21150	22600	24050	9999	Alleghany County	Virginia	0
VA	5100799999	51	7	METRO40060M40060	Richmond, VA MSA	Amelia County	89400	18800	21450	24150	26800	28950	31100	33250	35400	9999	Amelia County	Virginia	1
VA	5100999999	51	9	METRO31340M31340	Lynchburg, VA MSA	Amherst County	72400	15200	17400	19550	21700	23450	25200	26950	28650	4640	Amherst County	Virginia	1
VA	5101199999	51	11	METRO31340M31340	Lynchburg, VA MSA	Appomattox County	72400	15200	17400	19550	21700	23450	25200	26950	28650	9999	Appomattox County	Virginia	1
VA	5101399999	51	13	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Arlington County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Arlington County	Virginia	1
VA	5101599999	51	15	METRO44420M44420	Staunton-Waynesboro, VA MSA	Augusta County	71400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Augusta County	Virginia	1
VA	5101799999	51	17	NCNTY51017N51017	Bath County, VA	Bath County	65600	13800	15800	17750	19700	21300	22900	24450	26050	9999	Bath County	Virginia	0
VA	5101999999	51	19	METRO31340M31340	Lynchburg, VA MSA	Bedford County	72400	15200	17400	19550	21700	23450	25200	26950	28650	4640	Bedford County	Virginia	1
VA	5102199999	51	21	NCNTY51021N51021	Bland County, VA	Bland County	62200	13100	14950	16800	18650	20150	21650	23150	24650	9999	Bland County	Virginia	0
VA	5102399999	51	23	METRO40220M40220	Roanoke, VA HUD Metro FMR Area	Botetourt County	76700	16100	18400	20700	23000	24850	26700	28550	30400	6800	Botetourt County	Virginia	1
VA	5102599999	51	25	NCNTY51025N51025	Brunswick County, VA	Brunswick County	55800	12700	14500	16300	18100	19550	21000	22450	23900	9999	Brunswick County	Virginia	0
VA	5102799999	51	27	NCNTY51027N51027	Buchanan County, VA	Buchanan County	41700	12700	14500	16300	18100	19550	21000	22450	23900	9999	Buchanan County	Virginia	0
VA	5102999999	51	29	METRO16820N51029	Buckingham County, VA HUD Metro FMR Area	Buckingham County	61700	12950	14800	16650	18500	20000	21500	22950	24450	9999	Buckingham County	Virginia	1
VA	5103199999	51	31	METRO31340M31340	Lynchburg, VA MSA	Campbell County	72400	15200	17400	19550	21700	23450	25200	26950	28650	4640	Campbell County	Virginia	1
VA	5103399999	51	33	METRO40060M40060	Richmond, VA MSA	Caroline County	89400	18800	21450	24150	26800	28950	31100	33250	35400	9999	Caroline County	Virginia	1
VA	5103599999	51	35	NCNTY51035N51035	Carroll County-Galax city, VA HUD Nonmetro FMR Area	Carroll County	54600	12700	14500	16300	18100	19550	21000	22450	23900	9999	Carroll County	Virginia	0
VA	5103699999	51	36	METRO40060M40060	Richmond, VA MSA	Charles City County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Charles City County	Virginia	1
VA	5103799999	51	37	NCNTY51037N51037	Charlotte County, VA	Charlotte County	51100	12700	14500	16300	18100	19550	21000	22450	23900	9999	Charlotte County	Virginia	0
VA	5104199999	51	41	METRO40060M40060	Richmond, VA MSA	Chesterfield County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Chesterfield County	Virginia	1
VA	5104399999	51	43	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Clarke County	126000	26500	30250	34050	37800	40850	43850	46900	49900	1650	Clarke County	Virginia	1
VA	5104599999	51	45	METRO40220M40220	Roanoke, VA HUD Metro FMR Area	Craig County	76700	16100	18400	20700	23000	24850	26700	28550	30400	9999	Craig County	Virginia	1
VA	5104799999	51	47	METRO47900N51047	Culpeper County, VA HUD Metro FMR Area	Culpeper County	85200	17900	20450	23000	25550	27600	29650	31700	33750	1891	Culpeper County	Virginia	1
VA	5104999999	51	49	NCNTY51049N51049	Cumberland County, VA	Cumberland County	63200	13300	15200	17100	18950	20500	22000	23500	25050	9999	Cumberland County	Virginia	0
VA	5105199999	51	51	NCNTY51051N51051	Dickenson County, VA	Dickenson County	42600	12700	14500	16300	18100	19550	21000	22450	23900	9999	Dickenson County	Virginia	0
VA	5105399999	51	53	METRO40060M40060	Richmond, VA MSA	Dinwiddie County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Dinwiddie County	Virginia	1
VA	5105799999	51	57	NCNTY51057N51057	Essex County, VA	Essex County	63600	13350	15250	17150	19050	20600	22100	23650	25150	9999	Essex County	Virginia	0
VA	5105999999	51	59	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Fairfax County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Fairfax County	Virginia	1
VA	5106199999	51	61	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Fauquier County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Fauquier County	Virginia	1
VA	5106399999	51	63	METRO13980N51063	Floyd County, VA HUD Metro FMR Area	Floyd County	61600	12950	14800	16650	18500	20000	21500	22950	24450	9999	Floyd County	Virginia	1
VA	5106599999	51	65	METRO16820M16820	Charlottesville, VA HUD Metro FMR Area	Fluvanna County	93900	19750	22550	25350	28150	30450	32700	34950	37200	1540	Fluvanna County	Virginia	1
VA	5106799999	51	67	METRO40220N51067	Franklin County, VA HUD Metro FMR Area	Franklin County	67200	14150	16150	18150	20150	21800	23400	25000	26600	9999	Franklin County	Virginia	1

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VA	5106999999	51	69	METRO49020M49020	Winchester, VA-WV MSA	Frederick County	83400	16700	19050	21450	23800	25750	27650	29550	31450	9999	Frederick County	Virginia	1
VA	5107199999	51	71	METRO13980N51071	Giles County, VA HUD Metro FMR Area	Giles County	61000	12850	14650	16500	18300	19800	21250	22700	24200	9999	Giles County	Virginia	1
VA	5107399999	51	73	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Gloucester County	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Gloucester County	Virginia	1
VA	5107599999	51	75	METRO40060M40060	Richmond, VA MSA	Goochland County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Goochland County	Virginia	1
VA	5107799999	51	77	NCNTY51077N51077	Grayson County, VA	Grayson County	47900	12700	14500	16300	18100	19550	21000	22450	23900	9999	Grayson County	Virginia	0
VA	5107999999	51	79	METRO16820M16820	Charlottesville, VA HUD Metro FMR Area	Greene County	93900	19750	22550	25350	28150	30450	32700	34950	37200	1540	Greene County	Virginia	1
VA	5108199999	51	81	NCNTY51081N51081	Greensville County-Emporia city, VA HUD Nonmetro FMR Area	Greensville County	50400	12700	14500	16300	18100	19550	21000	22450	23900	9999	Greensville County	Virginia	0
VA	5108399999	51	83	NCNTY51083N51083	Halifax County, VA	Halifax County	58900	12700	14500	16300	18100	19550	21000	22450	23900	9999	Halifax County	Virginia	0
VA	5108599999	51	85	METRO40060M40060	Richmond, VA MSA	Hanover County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Hanover County	Virginia	1
VA	5108799999	51	87	METRO40060M40060	Richmond, VA MSA	Henrico County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Henrico County	Virginia	1
VA	5108999999	51	89	NCNTY51089N51089	Henry County-Martinsville city, VA HUD Nonmetro FMR Area	Henry County	52300	12700	14500	16300	18100	19550	21000	22450	23900	9999	Henry County	Virginia	0
VA	5109199999	51	91	NCNTY51091N51091	Highland County, VA	Highland County	64000	13450	15400	17300	19200	20750	22300	23850	25350	9999	Highland County	Virginia	0
VA	5109399999	51	93	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Isle of Wight County	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Isle of Wight County	Virginia	1
VA	5109599999	51	95	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	James City County	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	James City County	Virginia	1
VA	5109799999	51	97	NCNTY51097N51097	King and Queen County, VA	King and Queen County	60600	12750	14600	16400	18200	19700	21150	22600	24050	9999	King and Queen County	Virginia	0
VA	5109999999	51	99	NCNTY51099N51099	King George County, VA	King George County	99800	21000	24000	27000	29950	32350	34750	37150	39550	3830	King George County	Virginia	0
VA	5110199999	51	101	METRO40060M40060	Richmond, VA MSA	King William County	89400	18800	21450	24150	26800	28950	31100	33250	35400	9999	King William County	Virginia	1
VA	5110399999	51	103	NCNTY51103N51103	Lancaster County, VA	Lancaster County	71600	15050	17200	19350	21500	23250	24950	26700	28400	9999	Lancaster County	Virginia	0
VA	5110599999	51	105	NCNTY51105N51105	Lee County, VA	Lee County	49300	12700	14500	16300	18100	19550	21000	22450	23900	9999	Lee County	Virginia	0
VA	5110799999	51	107	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Loudoun County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Loudoun County	Virginia	1
VA	5110999999	51	109	NCNTY51109N51109	Louisa County, VA	Louisa County	74300	15650	17850	20100	22300	24100	25900	27700	29450	9999	Louisa County	Virginia	0
VA	5111199999	51	111	NCNTY51111N51111	Lunenburg County, VA	Lunenburg County	50200	12700	14500	16300	18100	19550	21000	22450	23900	9999	Lunenburg County	Virginia	0
VA	5111399999	51	113	NCNTY51113N51113	Madison County, VA	Madison County	61700	12950	14800	16650	18500	20000	21500	22950	24450	9999	Madison County	Virginia	0
VA	5111599999	51	115	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Mathews County	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Mathews County	Virginia	1
VA	5111799999	51	117	NCNTY51117N51117	Mecklenburg County, VA	Mecklenburg County	58000	12700	14500	16300	18100	19550	21000	22450	23900	9999	Mecklenburg County	Virginia	0
VA	5111999999	51	119	NCNTY51119N51119	Middlesex County, VA	Middlesex County	64100	13500	15400	17350	19250	20800	22350	23900	25450	9999	Middlesex County	Virginia	0
VA	5112199999	51	121	METRO13980M13980	Blacksburg-Christiansburg-Radford, VA HUD Metro FMR Area	Montgomery County	87800	17400	19850	22350	24800	26800	28800	30800	32750	9999	Montgomery County	Virginia	1
VA	5112599999	51	125	METRO16820M16820	Charlottesville, VA HUD Metro FMR Area	Nelson County	93900	19750	22550	25350	28150	30450	32700	34950	37200	9999	Nelson County	Virginia	1
VA	5112799999	51	127	METRO40060M40060	Richmond, VA MSA	New Kent County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	New Kent County	Virginia	1
VA	5113199999	51	131	NCNTY51131N51131	Northampton County, VA	Northampton County	58000	12700	14500	16300	18100	19550	21000	22450	23900	9999	Northampton County	Virginia	0
VA	5113399999	51	133	NCNTY51133N51133	Northumberland County, VA	Northumberland County	69800	14700	16800	18900	20950	22650	24350	26000	27700	9999	Northumberland County	Virginia	0
VA	5113599999	51	135	NCNTY51135N51135	Nottoway County, VA	Nottoway County	50700	12700	14500	16300	18100	19550	21000	22450	23900	9999	Nottoway County	Virginia	0
VA	5113799999	51	137	NCNTY51137N51137	Orange County, VA	Orange County	81600	17150	19600	22050	24500	26500	28450	30400	32350	9999	Orange County	Virginia	0
VA	5113999999	51	139	NCNTY51139N51139	Page County, VA	Page County	57000	12700	14500	16300	18100	19550	21000	22450	23900	9999	Page County	Virginia	0
VA	5114199999	51	141	NCNTY51141N51141	Patrick County, VA	Patrick County	56300	12700	14500	16300	18100	19550	21000	22450	23900	9999	Patrick County	Virginia	0
VA	5114399999	51	143	NCNTY51143N51143	Pittsylvania County-Danville city, VA HUD Nonmetro FMR Area	Pittsylvania County	58900	12700	14500	16300	18100	19550	21000	22450	23900	1950	Pittsylvania County	Virginia	0
VA	5114599999	51	145	METRO40060M40060	Richmond, VA MSA	Powhatan County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Powhatan County	Virginia	1

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VA	5114799999	51	147	NCNTY51147N51147	Prince Edward County, VA	Prince Edward County	59400	12700	14500	16300	18100	19550	21000	22450	23900	9999	Prince Edward County	Virginia	0
VA	5114999999	51	149	METRO40060M40060	Richmond, VA MSA	Prince George County	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Prince George County	Virginia	1
VA	5115399999	51	153	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Prince William County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Prince William County	Virginia	1
VA	5115599999	51	155	METRO13980N51155	Pulaski County, VA HUD Metro FMR Area	Pulaski County	60500	12750	14550	16350	18150	19650	21100	22550	24000	9999	Pulaski County	Virginia	1
VA	5115799999	51	157	METRO47900N51157	Rappahannock County, VA HUD Metro FMR Area	Rappahannock County	88700	17650	20150	22650	25150	27200	29200	31200	33200	9999	Rappahannock County	Virginia	1
VA	5115999999	51	159	NCNTY51159N51159	Richmond County, VA	Richmond County	56500	12700	14500	16300	18100	19550	21000	22450	23900	9999	Richmond County	Virginia	0
VA	5116199999	51	161	METRO40220M40220	Roanoke, VA HUD Metro FMR Area	Roanoke County	76700	16100	18400	20700	23000	24850	26700	28550	30400	6800	Roanoke County	Virginia	1
VA	5116399999	51	163	NCNTY51163N51163	Rockbridge County-Buena Vista city-Lexington city, VA HUD Nonmetr	Rockbridge County	61200	12850	14700	16550	18350	19850	21300	22800	24250	9999	Rockbridge County	Virginia	0
VA	5116599999	51	165	METRO25500M25500	Harrisonburg, VA MSA	Rockingham County	71900	15100	17250	19400	21550	23300	25000	26750	28450	9999	Rockingham County	Virginia	1
VA	5116799999	51	167	NCNTY51167N51167	Russell County, VA	Russell County	56000	12700	14500	16300	18100	19550	21000	22450	23900	9999	Russell County	Virginia	0
VA	5116999999	51	169	METRO28700M28700	Kingsport-Bristol-Bristol, TN-VA MSA	Scott County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3660	Scott County	Virginia	1
VA	5117199999	51	171	NCNTY51171N51171	Shenandoah County, VA	Shenandoah County	67900	14250	16300	18350	20350	22000	23650	25250	26900	9999	Shenandoah County	Virginia	0
VA	5117399999	51	173	NCNTY51173N51173	Smyth County, VA	Smyth County	53500	12700	14500	16300	18100	19550	21000	22450	23900	9999	Smyth County	Virginia	0
VA	5117599999	51	175	NCNTY51175N51175	Southampton County-Franklin city, VA HUD Nonmetro FMR Area	Southampton County	66300	13950	15950	17950	19900	21500	23100	24700	26300	9999	Southampton County	Virginia	0
VA	5117799999	51	177	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Spotsylvania County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Spotsylvania County	Virginia	1
VA	5117999999	51	179	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Stafford County	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Stafford County	Virginia	1
VA	5118199999	51	181	NCNTY51181N51181	Surry County, VA	Surry County	65000	13650	15600	17550	19500	21100	22650	24200	25750	9999	Surry County	Virginia	0
VA	5118399999	51	183	METRO40060M40060	Richmond, VA MSA	Sussex County	89400	18800	21450	24150	26800	28950	31100	33250	35400	9999	Sussex County	Virginia	1
VA	5118599999	51	185	NCNTY51185N51185	Tazewell County, VA	Tazewell County	55600	12700	14500	16300	18100	19550	21000	22450	23900	9999	Tazewell County	Virginia	0
VA	5118799999	51	187	METRO47900MM8820	Warren County, VA HUD Metro FMR Area	Warren County	81400	17100	19550	22000	24400	26400	28350	30300	32250	8820	Warren County	Virginia	1
VA	5119199999	51	191	METRO28700M28700	Kingsport-Bristol-Bristol, TN-VA MSA	Washington County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3660	Washington County	Virginia	1
VA	5119399999	51	193	NCNTY51193N51193	Westmoreland County, VA	Westmoreland County	76900	15400	17600	19800	21950	23750	25500	27250	29000	9999	Westmoreland County	Virginia	0
VA	5119599999	51	195	NCNTY51195N51195	Wise County-Norton city, VA HUD Nonmetro FMR Area	Wise County	50600	12700	14500	16300	18100	19550	21000	22450	23900	9999	Wise County	Virginia	0
VA	5119799999	51	197	NCNTY51197N51197	Wythe County, VA	Wythe County	58600	12700	14500	16300	18100	19550	21000	22450	23900	9999	Wythe County	Virginia	0
VA	5119999999	51	199	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	York County	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	York County	Virginia	1
VA	5151099999	51	510	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Alexandria city	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Alexandria city	Virginia	1
VA	5152099999	51	520	METRO28700M28700	Kingsport-Bristol-Bristol, TN-VA MSA	Bristol city	59100	12450	14200	16000	17750	19200	20600	22050	23450	3660	Bristol city	Virginia	1
VA	5153099999	51	530	NCNTY51163N51163	Rockbridge County-Buena Vista city-Lexington city, VA HUD Nonmetr	Buena Vista city	61200	12850	14700	16550	18350	19850	21300	22800	24250	9999	Buena Vista city	Virginia	0
VA	5154099999	51	540	METRO16820M16820	Charlottesville, VA HUD Metro FMR Area	Charlottesville city	93900	19750	22550	25350	28150	30450	32700	34950	37200	1540	Charlottesville city	Virginia	1
VA	5155099999	51	550	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Chesapeake city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Chesapeake city	Virginia	1
VA	5157099999	51	570	METRO40060M40060	Richmond, VA MSA	Colonial Heights city	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Colonial Heights city	Virginia	1
VA	5158099999	51	580	NCNTY51005N51005	Alleghany County-Clifton Forge city-Covington city, VA HUD Nonmet	Covington city	60700	12750	14600	16400	18200	19700	21150	22600	24050	9999	Covington city	Virginia	0
VA	5159099999	51	590	NCNTY51143N51143	Pittsylvania County-Danville city, VA HUD Nonmetro FMR Area	Danville city	58900	12700	14500	16300	18100	19550	21000	22450	23900	1950	Danville city	Virginia	0
VA	5159599999	51	595	NCNTY51081N51081	Greensville County-Emporia city, VA HUD Nonmetro FMR Area	Emporia city	50400	12700	14500	16300	18100	19550	21000	22450	23900	9999	Emporia city	Virginia	0

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VA	5160099999	51	600	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Fairfax city	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Fairfax city	Virginia	1
VA	5161099999	51	610	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Falls Church city	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Falls Church city	Virginia	1
VA	5162099999	51	620	NCNTY51175N51175	Southampton County-Franklin city, VA HUD Nonmetro FMR Area	Franklin city	66300	13950	15950	17950	19900	21500	23100	24700	26300	9999	Franklin city	Virginia	0
VA	5163099999	51	630	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Fredericksburg city	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Fredericksburg city	Virginia	1
VA	5164099999	51	640	NCNTY51035N51035	Carroll County-Galax city, VA HUD Nonmetro FMR Area	Galax city	54600	12700	14500	16300	18100	19550	21000	22450	23900	9999	Galax city	Virginia	0
VA	5165099999	51	650	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Hampton city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Hampton city	Virginia	1
VA	5166099999	51	660	METRO25500M25500	Harrisonburg, VA MSA	Harrisonburg city	71900	15100	17250	19400	21550	23300	25000	26750	28450	9999	Harrisonburg city	Virginia	1
VA	5167099999	51	670	METRO40060M40060	Richmond, VA MSA	Hopewell city	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Hopewell city	Virginia	1
VA	5167899999	51	678	NCNTY51163N51163	Rockbridge County-Buena Vista city-Lexington city, VA HUD Nonmetr	Lexington city	61200	12850	14700	16550	18350	19850	21300	22800	24250	9999	Lexington city	Virginia	0
VA	5168099999	51	680	METRO31340M31340	Lynchburg, VA MSA	Lynchburg city	72400	15200	17400	19550	21700	23450	25200	26950	28650	4640	Lynchburg city	Virginia	1
VA	5168399999	51	683	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Manassas city	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Manassas city	Virginia	1
VA	5168599999	51	685	METRO47900M47900	Washington-Arlington-Alexandria, DC-VA-MD HUD Metro FMR Area	Manassas Park city	126000	26500	30250	34050	37800	40850	43850	46900	49900	8840	Manassas Park city	Virginia	1
VA	5169099999	51	690	NCNTY51089N51089	Henry County-Martinsville city, VA HUD Nonmetro FMR Area	Martinsville city	52300	12700	14500	16300	18100	19550	21000	22450	23900	9999	Martinsville city	Virginia	0
VA	5170099999	51	700	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Newport News city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Newport News city	Virginia	1
VA	5171099999	51	710	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Norfolk city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Norfolk city	Virginia	1
VA	5172099999	51	720	NCNTY51195N51195	Wise County-Norton city, VA HUD Nonmetro FMR Area	Norton city	50600	12700	14500	16300	18100	19550	21000	22450	23900	9999	Norton city	Virginia	0
VA	5173099999	51	730	METRO40060M40060	Richmond, VA MSA	Petersburg city	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Petersburg city	Virginia	1
VA	5173599999	51	735	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Poquoson city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Poquoson city	Virginia	1
VA	5174099999	51	740	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Portsmouth city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Portsmouth city	Virginia	1
VA	5175099999	51	750	METRO13980M13980	Blacksburg-Christiansburg-Radford, VA HUD Metro FMR Area	Radford city	87800	17400	19850	22350	24800	26800	28800	30800	32750	9999	Radford city	Virginia	1
VA	5176099999	51	760	METRO40060M40060	Richmond, VA MSA	Richmond city	89400	18800	21450	24150	26800	28950	31100	33250	35400	6760	Richmond city	Virginia	1
VA	5177099999	51	770	METRO40220M40220	Roanoke, VA HUD Metro FMR Area	Roanoke city	76700	16100	18400	20700	23000	24850	26700	28550	30400	6800	Roanoke city	Virginia	1
VA	5177599999	51	775	METRO40220M40220	Roanoke, VA HUD Metro FMR Area	Salem city	76700	16100	18400	20700	23000	24850	26700	28550	30400	6800	Salem city	Virginia	1
VA	5179099999	51	790	METRO44420M44420	Staunton-Waynesboro, VA MSA	Staunton city	71400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Staunton city	Virginia	1
VA	5180099999	51	800	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Suffolk city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Suffolk city	Virginia	1
VA	5181099999	51	810	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Virginia Beach city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Virginia Beach city	Virginia	1
VA	5182099999	51	820	METRO44420M44420	Staunton-Waynesboro, VA MSA	Waynesboro city	71400	15000	17150	19300	21400	23150	24850	26550	28250	9999	Waynesboro city	Virginia	1
VA	5183099999	51	830	METRO47260M47260	Virginia Beach-Norfolk-Newport News, VA-NC HUD Metro FMR Area	Williamsburg city	82500	17350	19800	22300	24750	26750	28750	30700	32700	5720	Williamsburg city	Virginia	1
VA	5184099999	51	840	METRO49020M49020	Winchester, VA-WV MSA	Winchester city	83400	16700	19050	21450	23800	25750	27650	29550	31450	9999	Winchester city	Virginia	1
WA	5300199999	53	1	NCNTY53001N53001	Adams County, WA	Adams County	58000	14150	16200	18200	20200	21850	23450	25050	26700	9999	Adams County	Washington	0
WA	5300399999	53	3	METRO30300M30300	Lewiston, ID-WA MSA	Asotin County	73900	14350	16400	18450	20450	22100	23750	25400	27000	9999	Asotin County	Washington	1
WA	5300599999	53	5	METRO28420M28420	Kennewick-Richland, WA MSA	Benton County	77500	16300	18600	20950	23250	25150	27000	28850	30700	6740	Benton County	Washington	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
WA	5300799999	53	7	METRO48300M48300	Wenatchee, WA MSA	Chelan County	69400	14600	16650	18750	20800	22500	24150	25800	27500	9999	Chelan County	Washington	1
WA	5300999999	53	9	NCNTY53009N53009	Clallam County, WA	Clallam County	66300	14150	16200	18200	20200	21850	23450	25050	26700	9999	Clallam County	Washington	0
WA	5301199999	53	11	METRO38900M38900	Portland-Vancouver-Hillsboro, OR-WA MSA	Clark County	92100	19400	22150	24900	27650	29900	32100	34300	36500	6440	Clark County	Washington	1
WA	5301399999	53	13	METRO47460N53013	Columbia County, WA HUD Metro FMR Area	Columbia County	66300	14150	16200	18200	20200	21850	23450	25050	26700	9999	Columbia County	Washington	1
WA	5301599999	53	15	METRO31020M31020	Longview, WA MSA	Cowlitz County	69200	14550	16600	18700	20750	22450	24100	25750	27400	9999	Cowlitz County	Washington	1
WA	5301799999	53	17	METRO48300M48300	Wenatchee, WA MSA	Douglas County	69400	14600	16650	18750	20800	22500	24150	25800	27500	9999	Douglas County	Washington	1
WA	5301999999	53	19	NCNTY53019N53019	Ferry County, WA	Ferry County	55100	14150	16200	18200	20200	21850	23450	25050	26700	9999	Ferry County	Washington	0
WA	5302199999	53	21	METRO28420M28420	Kennewick-Richland, WA MSA	Franklin County	77500	16300	18600	20950	23250	25150	27000	28850	30700	6740	Franklin County	Washington	1
WA	5302399999	53	23	NCNTY53023N53023	Garfield County, WA	Garfield County	64600	14150	16200	18200	20200	21850	23450	25050	26700	9999	Garfield County	Washington	0
WA	5302599999	53	25	NCNTY53025N53025	Grant County, WA	Grant County	74600	14600	16650	18750	20800	22500	24150	25800	27500	9999	Grant County	Washington	0
WA	5302799999	53	27	NCNTY53027N53027	Grays Harbor County, WA	Grays Harbor County	65300	14150	16200	18200	20200	21850	23450	25050	26700	9999	Grays Harbor County	Washington	0
WA	5302999999	53	29	NCNTY53029N53029	Island County, WA	Island County	76000	16000	18250	20550	22800	24650	26450	28300	30100	7600	Island County	Washington	0
WA	5303199999	53	31	NCNTY53031N53031	Jefferson County, WA	Jefferson County	68600	14450	16500	18550	20600	22250	23900	25550	27200	9999	Jefferson County	Washington	0
WA	5303399999	53	33	METRO42660MM7600	Seattle-Bellevue, WA HUD Metro FMR Area	King County	113300	25100	28650	32250	35800	38700	41550	44400	47300	7600	King County	Washington	1
WA	5303599999	53	35	METRO14740M14740	Bremerton-Silverdale, WA MSA	Kitsap County	91700	19250	22000	24750	27500	29700	31900	34100	36300	1150	Kitsap County	Washington	1
WA	5303799999	53	37	NCNTY53037N53037	Kittitas County, WA	Kittitas County	74900	15750	18000	20250	22450	24250	26050	27850	29650	9999	Kittitas County	Washington	0
WA	5303999999	53	39	NCNTY53039N53039	Klickitat County, WA	Klickitat County	65600	14150	16200	18200	20200	21850	23450	25050	26700	9999	Klickitat County	Washington	0
WA	5304199999	53	41	NCNTY53041N53041	Lewis County, WA	Lewis County	63400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lewis County	Washington	0
WA	5304399999	53	43	NCNTY53043N53043	Lincoln County, WA	Lincoln County	65400	14150	16200	18200	20200	21850	23450	25050	26700	9999	Lincoln County	Washington	0
WA	5304599999	53	45	NCNTY53045N53045	Mason County, WA	Mason County	65900	14150	16200	18200	20200	21850	23450	25050	26700	9999	Mason County	Washington	0
WA	5304799999	53	47	NCNTY53047N53047	Okanogan County, WA	Okanogan County	53900	14150	16200	18200	20200	21850	23450	25050	26700	9999	Okanogan County	Washington	0
WA	5304999999	53	49	NCNTY53049N53049	Pacific County, WA	Pacific County	57600	14150	16200	18200	20200	21850	23450	25050	26700	9999	Pacific County	Washington	0
WA	5305199999	53	51	METRO44060N53051	Pend Oreille County, WA HUD Metro FMR Area	Pend Oreille County	60700	14150	16200	18200	20200	21850	23450	25050	26700	9999	Pend Oreille County	Washington	1
WA	5305399999	53	53	METRO42660MM8200	Tacoma, WA HUD Metro FMR Area	Pierce County	87300	18200	20800	23400	25950	28050	30150	32200	34300	8200	Pierce County	Washington	1
WA	5305599999	53	55	NCNTY53055N53055	San Juan County, WA	San Juan County	78400	16450	18800	21150	23500	25400	27300	29150	31050	9999	San Juan County	Washington	0
WA	5305799999	53	57	METRO34580M34580	Mount Vernon-Anacortes, WA MSA	Skagit County	78400	16450	18800	21150	23500	25400	27300	29150	31050	9999	Skagit County	Washington	1
WA	5305999999	53	59	METRO38900M38900	Portland-Vancouver-Hillsboro, OR-WA MSA	Skamania County	92100	19400	22150	24900	27650	29900	32100	34300	36500	9999	Skamania County	Washington	1
WA	5306199999	53	61	METRO42660MM7600	Seattle-Bellevue, WA HUD Metro FMR Area	Snohomish County	113300	25100	28650	32250	35800	38700	41550	44400	47300	7600	Snohomish County	Washington	1
WA	5306399999	53	63	METRO44060M44060	Spokane, WA HUD Metro FMR Area	Spokane County	78500	16250	18600	20900	23200	25100	26950	28800	30650	7840	Spokane County	Washington	1
WA	5306599999	53	65	METRO44060N53065	Stevens County, WA HUD Metro FMR Area	Stevens County	63500	14150	16200	18200	20200	21850	23450	25050	26700	9999	Stevens County	Washington	1
WA	5306799999	53	67	METRO36500M36500	Olympia-Tumwater, WA MSA	Thurston County	86700	18200	20800	23400	26000	28100	30200	32250	34350	5910	Thurston County	Washington	1
WA	5306999999	53	69	NCNTY53069N53069	Wahkiakum County, WA	Wahkiakum County	61800	14150	16200	18200	20200	21850	23450	25050	26700	9999	Wahkiakum County	Washington	0
WA	5307199999	53	71	METRO47460N53071	Walla Walla County, WA HUD Metro FMR Area	Walla Walla County	69900	14700	16800	18900	20950	22650	24350	26000	27700	9999	Walla Walla County	Washington	1
WA	5307399999	53	73	METRO13380M13380	Bellingham, WA MSA	Whatcom County	86300	17950	20500	23050	25600	27650	29700	31750	33800	860	Whatcom County	Washington	1
WA	5307599999	53	75	NCNTY53075N53075	Whitman County, WA	Whitman County	72300	15200	17400	19550	21700	23450	25200	26950	28650	9999	Whitman County	Washington	0
WA	5307799999	53	77	METRO49420M49420	Yakima, WA MSA	Yakima County	57200	14150	16200	18200	20200	21850	23450	25050	26700	9260	Yakima County	Washington	1
WV	5400199999	54	1	NCNTY54001N54001	Barbour County, WV	Barbour County	50000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Barbour County	West Virginia	0
WV	5400399999	54	3	METRO25180MM0877	Martinsburg, WV HUD Metro FMR Area	Berkeley County	74300	15650	17850	20100	22300	24100	25900	27700	29450	877	Berkeley County	West Virginia	1
WV	5400599999	54	5	METRO16620N54005	Boone County, WV HUD Metro FMR Area	Boone County	50300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Boone County	West Virginia	1
WV	5400799999	54	7	NCNTY54007N54007	Braxton County, WV	Braxton County	55900	11750	13400	15100	16750	18100	19450	20800	22150	9999	Braxton County	West Virginia	0
WV	5400999999	54	9	METRO48260M48260	Weirton-Steubenville, WV-OH MSA	Brooke County	62400	13700	15650	17600	19550	21150	22700	24250	25850	8080	Brooke County	West Virginia	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
WV	5401199999	54	11	METRO26580M26580	Huntington-Ashland, WV-KY-OH HUD Metro FMR Area	Cabell County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3400	Cabell County	West Virginia	1
WV	5401399999	54	13	NCNTY54013N54013	Calhoun County, WV	Calhoun County	51000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Calhoun County	West Virginia	0
WV	5401599999	54	15	METRO16620M16620	Charleston, WV HUD Metro FMR Area	Clay County	55700	12800	14600	16450	18250	19750	21200	22650	24100	9999	Clay County	West Virginia	1
WV	5401799999	54	17	NCNTY54017N54017	Doddridge County, WV	Doddridge County	62100	12300	14050	15800	17550	19000	20400	21800	23200	9999	Doddridge County	West Virginia	0
WV	5401999999	54	19	METRO13220N54019	Fayette County, WV HUD Metro FMR Area	Fayette County	50600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Fayette County	West Virginia	1
WV	5402199999	54	21	NCNTY54021N54021	Gilmer County, WV	Gilmer County	52300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Gilmer County	West Virginia	0
WV	5402399999	54	23	NCNTY54023N54023	Grant County, WV	Grant County	54000	11550	13200	14850	16450	17800	19100	20400	21750	9999	Grant County	West Virginia	0
WV	5402599999	54	25	NCNTY54025N54025	Greenbrier County, WV	Greenbrier County	54400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Greenbrier County	West Virginia	0
WV	5402799999	54	27	METRO49020M49020	Winchester, VA-WV MSA	Hampshire County	83400	16700	19050	21450	23800	25750	27650	29550	31450	9999	Hampshire County	West Virginia	1
WV	5402999999	54	29	METRO48260M48260	Weirton-Steubenville, WV-OH MSA	Hancock County	62400	13700	15650	17600	19550	21150	22700	24250	25850	8080	Hancock County	West Virginia	1
WV	5403199999	54	31	NCNTY54031N54031	Hardy County, WV	Hardy County	49500	11550	13200	14850	16450	17800	19100	20400	21750	9999	Hardy County	West Virginia	0
WV	5403399999	54	33	NCNTY54033N54033	Harrison County, WV	Harrison County	77600	15650	17850	20100	22300	24100	25900	27700	29450	9999	Harrison County	West Virginia	0
WV	5403599999	54	35	NCNTY54035N54035	Jackson County, WV	Jackson County	58800	12400	14150	15900	17650	19100	20500	21900	23300	9999	Jackson County	West Virginia	0
WV	5403799999	54	37	METRO47900MM3630	Jefferson County, WV HUD Metro FMR Area	Jefferson County	94700	19900	22750	25600	28400	30700	32950	35250	37500	3630	Jefferson County	West Virginia	1
WV	5403999999	54	39	METRO16620M16620	Charleston, WV HUD Metro FMR Area	Kanawha County	55700	12800	14600	16450	18250	19750	21200	22650	24100	1480	Kanawha County	West Virginia	1
WV	5404199999	54	41	NCNTY54041N54041	Lewis County, WV	Lewis County	51600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Lewis County	West Virginia	0
WV	5404399999	54	43	METRO26580M54043	Lincoln County, WV HUD Metro FMR Area	Lincoln County	48700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Lincoln County	West Virginia	1
WV	5404599999	54	45	NCNTY54045N54045	Logan County, WV	Logan County	53300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Logan County	West Virginia	0
WV	5404799999	54	47	NCNTY54047N54047	McDowell County, WV	McDowell County	34000	11550	13200	14850	16450	17800	19100	20400	21750	9999	McDowell County	West Virginia	0
WV	5404999999	54	49	NCNTY54049N54049	Marion County, WV	Marion County	63600	13400	15300	17200	19100	20650	22200	23700	25250	9999	Marion County	West Virginia	0
WV	5405199999	54	51	METRO48540M48540	Wheeling, WV-OH MSA	Marshall County	68900	14500	16550	18600	20650	22350	24000	25650	27300	9000	Marshall County	West Virginia	1
WV	5405399999	54	53	NCNTY54053N54053	Mason County, WV	Mason County	52900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Mason County	West Virginia	0
WV	5405599999	54	55	NCNTY54055N54055	Mercer County, WV	Mercer County	53200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Mercer County	West Virginia	0
WV	5405799999	54	57	METRO19060M19060	Cumberland, MD-WV MSA	Mineral County	61900	15300	17500	19700	21850	23600	25350	27100	28850	1900	Mineral County	West Virginia	1
WV	5405999999	54	59	NCNTY54059N54059	Mingo County, WV	Mingo County	43100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Mingo County	West Virginia	0
WV	5406199999	54	61	METRO34060M34060	Morgantown, WV MSA	Monongalia County	73900	15550	17750	19950	22150	23950	25700	27500	29250	9999	Monongalia County	West Virginia	1
WV	5406399999	54	63	NCNTY54063N54063	Monroe County, WV	Monroe County	48200	11550	13200	14850	16450	17800	19100	20400	21750	9999	Monroe County	West Virginia	0
WV	5406599999	54	65	NCNTY54065N54065	Morgan County, WV	Morgan County	63600	13400	15300	17200	19100	20650	22200	23700	25250	9999	Morgan County	West Virginia	0
WV	5406799999	54	67	NCNTY54067N54067	Nicholas County, WV	Nicholas County	53700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Nicholas County	West Virginia	0
WV	5406999999	54	69	METRO48540M48540	Wheeling, WV-OH MSA	Ohio County	68900	14500	16550	18600	20650	22350	24000	25650	27300	9000	Ohio County	West Virginia	1
WV	5407199999	54	71	NCNTY54071N54071	Pendleton County, WV	Pendleton County	50100	11550	13200	14850	16450	17800	19100	20400	21750	9999	Pendleton County	West Virginia	0
WV	5407399999	54	73	NCNTY54073N54073	Pleasants County, WV	Pleasants County	59700	12550	14350	16150	17900	19350	20800	22200	23650	9999	Pleasants County	West Virginia	0
WV	5407599999	54	75	NCNTY54075N54075	Pocahontas County, WV	Pocahontas County	58200	12250	14000	15750	17450	18850	20250	21650	23050	9999	Pocahontas County	West Virginia	0
WV	5407799999	54	77	METRO34060M34060	Morgantown, WV MSA	Preston County	73900	15550	17750	19950	22150	23950	25700	27500	29250	9999	Preston County	West Virginia	1
WV	5407999999	54	79	METRO26580M54079	Putnam County, WV HUD Metro FMR Area	Putnam County	77100	16250	18550	20850	23150	25050	26900	28750	30600	1480	Putnam County	West Virginia	1
WV	5408199999	54	81	METRO13220N54081	Raleigh County, WV HUD Metro FMR Area	Raleigh County	54300	11550	13200	14850	16450	17800	19100	20400	21750	9999	Raleigh County	West Virginia	1
WV	5408399999	54	83	NCNTY54083N54083	Randolph County, WV	Randolph County	55800	11750	13400	15100	16750	18100	19450	20800	22150	9999	Randolph County	West Virginia	0
WV	5408599999	54	85	NCNTY54085N54085	Ritchie County, WV	Ritchie County	55000	11550	13200	14850	16500	17850	19150	20500	21800	9999	Ritchie County	West Virginia	0
WV	5408799999	54	87	NCNTY54087N54087	Roane County, WV	Roane County	48700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Roane County	West Virginia	0
WV	5408999999	54	89	NCNTY54089N54089	Summers County, WV	Summers County	45400	11550	13200	14850	16450	17800	19100	20400	21750	9999	Summers County	West Virginia	0
WV	5409199999	54	91	NCNTY54091N54091	Taylor County, WV	Taylor County	61300	12900	14750	16600	18400	19900	21350	22850	24300	9999	Taylor County	West Virginia	0
WV	5409399999	54	93	NCNTY54093N54093	Tucker County, WV	Tucker County	57900	12150	13900	15650	17350	18750	20150	21550	22950	9999	Tucker County	West Virginia	0
WV	5409599999	54	95	NCNTY54095N54095	Tyler County, WV	Tyler County	56800	11950	13650	15350	17050	18450	19800	21150	22550	9999	Tyler County	West Virginia	0
WV	5409799999	54	97	NCNTY54097N54097	Upshur County, WV	Upshur County	55300	11650	13300	14950	16600	17950	19300	20600	21950	9999	Upshur County	West Virginia	0
WV	5409999999	54	99	METRO26580M26580	Huntington-Ashland, WV-KY-OH HUD Metro FMR Area	Wayne County	59100	12450	14200	16000	17750	19200	20600	22050	23450	3400	Wayne County	West Virginia	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
WV	5410199999	54	101	NCNTY54101N54101	Webster County, WV	Webster County	44600	11550	13200	14850	16450	17800	19100	20400	21750	9999	Webster County	West Virginia	0
WV	5410399999	54	103	NCNTY54103N54103	Wetzel County, WV	Wetzel County	51700	11550	13200	14850	16450	17800	19100	20400	21750	9999	Wetzel County	West Virginia	0
WV	5410599999	54	105	METRO37620M37620	Parkersburg-Vienna, WV MSA	Wirt County	64300	13300	15200	17100	19000	20550	22050	23600	25100	9999	Wirt County	West Virginia	1
WV	5410799999	54	107	METRO37620M37620	Parkersburg-Vienna, WV MSA	Wood County	64300	13300	15200	17100	19000	20550	22050	23600	25100	6020	Wood County	West Virginia	1
WV	5410999999	54	109	NCNTY54109N54109	Wyoming County, WV	Wyoming County	51900	11550	13200	14850	16450	17800	19100	20400	21750	9999	Wyoming County	West Virginia	0
WI	5500199999	55	1	NCNTY55001N55001	Adams County, WI	Adams County	55600	14900	17000	19150	21250	22950	24650	26350	28050	9999	Adams County	Wisconsin	0
WI	5500399999	55	3	NCNTY55003N55003	Ashland County, WI	Ashland County	59000	14900	17000	19150	21250	22950	24650	26350	28050	9999	Ashland County	Wisconsin	0
WI	5500599999	55	5	NCNTY55005N55005	Barron County, WI	Barron County	65000	14900	17000	19150	21250	22950	24650	26350	28050	9999	Barron County	Wisconsin	0
WI	5500799999	55	7	NCNTY55007N55007	Bayfield County, WI	Bayfield County	64500	14900	17000	19150	21250	22950	24650	26350	28050	9999	Bayfield County	Wisconsin	0
WI	5500999999	55	9	METRO24580M24580	Green Bay, WI HUD Metro FMR Area	Brown County	82300	17300	19800	22250	24700	26700	28700	30650	32650	3080	Brown County	Wisconsin	1
WI	5501199999	55	11	NCNTY55011N55011	Buffalo County, WI	Buffalo County	68500	14900	17000	19150	21250	22950	24650	26350	28050	9999	Buffalo County	Wisconsin	0
WI	5501399999	55	13	NCNTY55013N55013	Burnett County, WI	Burnett County	59800	14900	17000	19150	21250	22950	24650	26350	28050	9999	Burnett County	Wisconsin	0
WI	5501599999	55	15	METRO11540M11540	Appleton, WI MSA	Calumet County	86400	18150	20750	23350	25900	28000	30050	32150	34200	460	Calumet County	Wisconsin	1
WI	5501799999	55	17	METRO20740M20740	Eau Claire, WI MSA	Chippewa County	76700	16100	18400	20700	23000	24850	26700	28550	30400	2290	Chippewa County	Wisconsin	1
WI	5501999999	55	19	NCNTY55019N55019	Clark County, WI	Clark County	62900	14900	17000	19150	21250	22950	24650	26350	28050	9999	Clark County	Wisconsin	0
WI	5502199999	55	21	METRO31540N55021	Columbia County, WI HUD Metro FMR Area	Columbia County	81800	17200	19650	22100	24550	26550	28500	30450	32450	9999	Columbia County	Wisconsin	1
WI	5502399999	55	23	NCNTY55023N55023	Crawford County, WI	Crawford County	64300	14900	17000	19150	21250	22950	24650	26350	28050	9999	Crawford County	Wisconsin	0
WI	5502599999	55	25	METRO31540M31540	Madison, WI HUD Metro FMR Area	Dane County	100100	21050	24050	27050	30050	32500	34900	37300	39700	4720	Dane County	Wisconsin	1
WI	5502799999	55	27	NCNTY55027N55027	Dodge County, WI	Dodge County	77500	16300	18600	20950	23250	25150	27000	28850	30700	9999	Dodge County	Wisconsin	0
WI	5502999999	55	29	NCNTY55029N55029	Door County, WI	Door County	74500	15650	17900	20150	22350	24150	25950	27750	29550	9999	Door County	Wisconsin	0
WI	5503199999	55	31	METRO20260M20260	Duluth, MN-WI MSA	Douglas County	76800	16150	18450	20750	23050	24900	26750	28600	30450	2240	Douglas County	Wisconsin	1
WI	5503399999	55	33	NCNTY55033N55033	Dunn County, WI	Dunn County	71500	15050	17200	19350	21450	23200	24900	26600	28350	9999	Dunn County	Wisconsin	0
WI	5503599999	55	35	METRO20740M20740	Eau Claire, WI MSA	Eau Claire County	76700	16100	18400	20700	23000	24850	26700	28550	30400	2290	Eau Claire County	Wisconsin	1
WI	5503799999	55	37	NCNTY55037N55037	Florence County, WI	Florence County	61000	14900	17000	19150	21250	22950	24650	26350	28050	9999	Florence County	Wisconsin	0
WI	5503999999	55	39	METRO22540M22540	Fond du Lac, WI MSA	Fond du Lac County	79200	16650	19000	21400	23750	25650	27550	29450	31350	9999	Fond du Lac County	Wisconsin	1
WI	5504199999	55	41	NCNTY55041N55041	Forest County, WI	Forest County	56000	14900	17000	19150	21250	22950	24650	26350	28050	9999	Forest County	Wisconsin	0
WI	5504399999	55	43	NCNTY55043N55043	Grant County, WI	Grant County	68500	14900	17000	19150	21250	22950	24650	26350	28050	9999	Grant County	Wisconsin	0
WI	5504599999	55	45	METRO31540N55045	Green County, WI HUD Metro FMR Area	Green County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Green County	Wisconsin	1
WI	5504799999	55	47	NCNTY55047N55047	Green Lake County, WI	Green Lake County	69900	14900	17000	19150	21250	22950	24650	26350	28050	9999	Green Lake County	Wisconsin	0
WI	5504999999	55	49	METRO31540N55049	Iowa County, WI HUD Metro FMR Area	Iowa County	78500	16500	18850	21200	23550	25450	27350	29250	31100	9999	Iowa County	Wisconsin	1
WI	5505199999	55	51	NCNTY55051N55051	Iron County, WI	Iron County	57200	14900	17000	19150	21250	22950	24650	26350	28050	9999	Iron County	Wisconsin	0
WI	5505399999	55	53	NCNTY55053N55053	Jackson County, WI	Jackson County	66100	14900	17000	19150	21250	22950	24650	26350	28050	9999	Jackson County	Wisconsin	0
WI	5505599999	55	55	NCNTY55055N55055	Jefferson County, WI	Jefferson County	76600	16100	18400	20700	23000	24850	26700	28550	30400	9999	Jefferson County	Wisconsin	0
WI	5505799999	55	57	NCNTY55057N55057	Juneau County, WI	Juneau County	63400	14900	17000	19150	21250	22950	24650	26350	28050	9999	Juneau County	Wisconsin	0
WI	5505999999	55	59	METRO16980MM3800	Kenosha County, WI HUD Metro FMR Area	Kenosha County	77700	16350	18650	21000	23300	25200	27050	28900	30800	3800	Kenosha County	Wisconsin	1
WI	5506199999	55	61	METRO24580M24580	Green Bay, WI HUD Metro FMR Area	Kewaunee County	82300	17300	19800	22250	24700	26700	28700	30650	32650	9999	Kewaunee County	Wisconsin	1
WI	5506399999	55	63	METRO29100M29100	La Crosse-Onalaska, WI-MN MSA	La Crosse County	76800	16150	18450	20750	23050	24900	26750	28600	30450	3870	La Crosse County	Wisconsin	1
WI	5506599999	55	65	NCNTY55065N55065	Lafayette County, WI	Lafayette County	69400	14900	17000	19150	21250	22950	24650	26350	28050	9999	Lafayette County	Wisconsin	0
WI	5506799999	55	67	NCNTY55067N55067	Langlade County, WI	Langlade County	60300	14900	17000	19150	21250	22950	24650	26350	28050	9999	Langlade County	Wisconsin	0
WI	5506999999	55	69	NCNTY55069N55069	Lincoln County, WI	Lincoln County	71700	15050	17200	19350	21500	23250	24950	26700	28400	9999	Lincoln County	Wisconsin	0
WI	5507199999	55	71	NCNTY55071N55071	Manitowoc County, WI	Manitowoc County	76000	15650	17850	20100	22300	24100	25900	27700	29450	9999	Manitowoc County	Wisconsin	0
WI	5507399999	55	73	METRO48140M48140	Wausau, WI MSA	Marathon County	79900	16600	19000	21350	23700	25600	27500	29400	31300	8940	Marathon County	Wisconsin	1
WI	5507599999	55	75	NCNTY55075N55075	Marinette County, WI	Marinette County	59200	14900	17000	19150	21250	22950	24650	26350	28050	9999	Marinette County	Wisconsin	0
WI	5507799999	55	77	NCNTY55077N55077	Marquette County, WI	Marquette County	64300	14900	17000	19150	21250	22950	24650	26350	28050	9999	Marquette County	Wisconsin	0
WI	5507899999	55	78	NCNTY55078N55078	Menominee County, WI	Menominee County	41000	14900	17000	19150	21250	22950	24650	26350	28050	9999	Menominee County	Wisconsin	0
WI	5507999999	55	79	METRO33340M33340	Milwaukee-Waukesha-West Allis, WI MSA	Milwaukee County	83800	17650	20150	22650	25150	27200	29200	31200	33200	5080	Milwaukee County	Wisconsin	1
WI	5508199999	55	81	NCNTY55081N55081	Monroe County, WI	Monroe County	72100	15200	17350	19500	21650	23400	25150	26850	28600	9999	Monroe County	Wisconsin	0
WI	5508399999	55	83	METRO24580N55083	Oconto County, WI HUD Metro FMR Area	Oconto County	70700	14900	17000	19150	21250	22950	24650	26350	28050	9999	Oconto County	Wisconsin	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
WI	5508599999	55	85	NCNTY55085N55085	Oneida County, WI	Oneida County	70400	14900	17000	19150	21250	22950	24650	26350	28050	9999	Oneida County	Wisconsin	0
WI	5508799999	55	87	METRO11540M11540	Appleton, WI MSA	Outagamie County	86400	18150	20750	23350	25900	28000	30050	32150	34200	460	Outagamie County	Wisconsin	1
WI	5508999999	55	89	METRO33340M33340	Milwaukee-Waukesha-West Allis, WI MSA	Ozaukee County	83800	17650	20150	22650	25150	27200	29200	31200	33200	5080	Ozaukee County	Wisconsin	1
WI	5509199999	55	91	NCNTY55091N55091	Pepin County, WI	Pepin County	68500	14900	17000	19150	21250	22950	24650	26350	28050	9999	Pepin County	Wisconsin	0
WI	5509399999	55	93	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	Pierce County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	Pierce County	Wisconsin	1
WI	5509599999	55	95	NCNTY55095N55095	Polk County, WI	Polk County	69200	14900	17000	19150	21250	22950	24650	26350	28050	9999	Polk County	Wisconsin	0
WI	5509799999	55	97	NCNTY55097N55097	Portage County, WI	Portage County	79100	16500	18850	21200	23550	25450	27350	29250	31100	9999	Portage County	Wisconsin	0
WI	5509999999	55	99	NCNTY55099N55099	Price County, WI	Price County	60500	14900	17000	19150	21250	22950	24650	26350	28050	9999	Price County	Wisconsin	0
WI	5510199999	55	101	METRO39540M39540	Racine, WI MSA	Racine County	84600	16150	18450	20750	23050	24900	26750	28600	30450	6600	Racine County	Wisconsin	1
WI	5510399999	55	103	NCNTY55103N55103	Richland County, WI	Richland County	63200	14900	17000	19150	21250	22950	24650	26350	28050	9999	Richland County	Wisconsin	0
WI	5510599999	55	105	METRO27500M27500	Janesville-Beloit, WI MSA	Rock County	70300	14900	17000	19150	21250	22950	24650	26350	28050	3620	Rock County	Wisconsin	1
WI	5510799999	55	107	NCNTY55107N55107	Rusk County, WI	Rusk County	53700	14900	17000	19150	21250	22950	24650	26350	28050	9999	Rusk County	Wisconsin	0
WI	5510999999	55	109	METRO33460M33460	Minneapolis-St. Paul-Bloomington, MN-WI HUD Metro FMR Area	St. Croix County	103400	21700	24800	27900	31000	33500	36000	38450	40950	5120	St. Croix County	Wisconsin	1
WI	5511199999	55	111	NCNTY55111N55111	Sauk County, WI	Sauk County	72500	15250	17400	19600	21750	23500	25250	27000	28750	9999	Sauk County	Wisconsin	0
WI	5511399999	55	113	NCNTY55113N55113	Sawyer County, WI	Sawyer County	55400	14900	17000	19150	21250	22950	24650	26350	28050	9999	Sawyer County	Wisconsin	0
WI	5511599999	55	115	NCNTY55115N55115	Shawano County, WI	Shawano County	66400	14900	17000	19150	21250	22950	24650	26350	28050	9999	Shawano County	Wisconsin	0
WI	5511799999	55	117	METRO43100M43100	Sheboygan, WI MSA	Sheboygan County	73400	15400	17600	19800	22000	23800	25550	27300	29050	7620	Sheboygan County	Wisconsin	1
WI	5511999999	55	119	NCNTY55119N55119	Taylor County, WI	Taylor County	63900	14900	17000	19150	21250	22950	24650	26350	28050	9999	Taylor County	Wisconsin	0
WI	5512199999	55	121	NCNTY55121N55121	Trempealeau County, WI	Trempealeau County	71900	15100	17250	19400	21550	23300	25000	26750	28450	9999	Trempealeau County	Wisconsin	0
WI	5512399999	55	123	NCNTY55123N55123	Vernon County, WI	Vernon County	63600	14900	17000	19150	21250	22950	24650	26350	28050	9999	Vernon County	Wisconsin	0
WI	5512599999	55	125	NCNTY55125N55125	Vilas County, WI	Vilas County	57500	14900	17000	19150	21250	22950	24650	26350	28050	9999	Vilas County	Wisconsin	0
WI	5512799999	55	127	NCNTY55127N55127	Walworth County, WI	Walworth County	79000	16600	19000	21350	23700	25600	27500	29400	31300	9999	Walworth County	Wisconsin	0
WI	5512999999	55	129	NCNTY55129N55129	Washburn County, WI	Washburn County	63800	14900	17000	19150	21250	22950	24650	26350	28050	9999	Washburn County	Wisconsin	0
WI	5513199999	55	131	METRO33340M33340	Milwaukee-Waukesha-West Allis, WI MSA	Washington County	83800	17650	20150	22650	25150	27200	29200	31200	33200	5080	Washington County	Wisconsin	1
WI	5513399999	55	133	METRO33340M33340	Milwaukee-Waukesha-West Allis, WI MSA	Waukesha County	83800	17650	20150	22650	25150	27200	29200	31200	33200	5080	Waukesha County	Wisconsin	1
WI	5513599999	55	135	NCNTY55135N55135	Waupaca County, WI	Waupaca County	71800	15100	17250	19400	21550	23300	25000	26750	28450	9999	Waupaca County	Wisconsin	0
WI	5513799999	55	137	NCNTY55137N55137	Waushara County, WI	Waushara County	63700	14900	17000	19150	21250	22950	24650	26350	28050	9999	Waushara County	Wisconsin	0
WI	5513999999	55	139	METRO36780M36780	Oshkosh-Neenah, WI MSA	Winnebago County	80800	17000	19400	21850	24250	26200	28150	30100	32050	460	Winnebago County	Wisconsin	1
WI	5514199999	55	141	NCNTY55141N55141	Wood County, WI	Wood County	73600	15500	17700	19900	22100	23900	25650	27450	29200	9999	Wood County	Wisconsin	0
WY	5600199999	56	1	NCNTY56001N56001	Albany County, WY	Albany County	78900	16750	19150	21550	23900	25850	27750	29650	31550	9999	Albany County	Wyoming	0
WY	5600399999	56	3	NCNTY56003N56003	Big Horn County, WY	Big Horn County	66400	16750	19150	21550	23900	25850	27750	29650	31550	9999	Big Horn County	Wyoming	0
WY	5600599999	56	5	NCNTY56005N56005	Campbell County, WY	Campbell County	93900	19750	22550	25350	28150	30450	32700	34950	37200	9999	Campbell County	Wyoming	0
WY	5600799999	56	7	NCNTY56007N56007	Carbon County, WY	Carbon County	77600	16750	19150	21550	23900	25850	27750	29650	31550	9999	Carbon County	Wyoming	0
WY	5600999999	56	9	NCNTY56009N56009	Converse County, WY	Converse County	84300	17750	20250	22800	25300	27350	29350	31400	33400	9999	Converse County	Wyoming	0
WY	5601199999	56	11	NCNTY56011N56011	Crook County, WY	Crook County	84000	17650	20200	22700	25200	27250	29250	31250	33300	9999	Crook County	Wyoming	0
WY	5601399999	56	13	NCNTY56013N56013	Fremont County, WY	Fremont County	71200	16750	19150	21550	23900	25850	27750	29650	31550	9999	Fremont County	Wyoming	0
WY	5601599999	56	15	NCNTY56015N56015	Goshen County, WY	Goshen County	68100	16750	19150	21550	23900	25850	27750	29650	31550	9999	Goshen County	Wyoming	0
WY	5601799999	56	17	NCNTY56017N56017	Hot Springs County, WY	Hot Springs County	72500	16750	19150	21550	23900	25850	27750	29650	31550	9999	Hot Springs County	Wyoming	0
WY	5601999999	56	19	NCNTY56019N56019	Johnson County, WY	Johnson County	62700	16750	19150	21550	23900	25850	27750	29650	31550	9999	Johnson County	Wyoming	0
WY	5602199999	56	21	METRO16940M16940	Cheyenne, WY MSA	Laramie County	78100	16750	19150	21550	23900	25850	27750	29650	31550	1580	Laramie County	Wyoming	1
WY	5602399999	56	23	NCNTY56023N56023	Lincoln County, WY	Lincoln County	77200	16750	19150	21550	23900	25850	27750	29650	31550	9999	Lincoln County	Wyoming	0
WY	5602599999	56	25	METRO16220M16220	Casper, WY MSA	Natrona County	79300	16750	19150	21550	23900	25850	27750	29650	31550	1350	Natrona County	Wyoming	1
WY	5602799999	56	27	NCNTY56027N56027	Niobrara County, WY	Niobrara County	65200	16750	19150	21550	23900	25850	27750	29650	31550	9999	Niobrara County	Wyoming	0
WY	5602999999	56	29	NCNTY56029N56029	Park County, WY	Park County	76600	16750	19150	21550	23900	25850	27750	29650	31550	9999	Park County	Wyoming	0
WY	5603199999	56	31	NCNTY56031N56031	Platte County, WY	Platte County	69300	16750	19150	21550	23900	25850	27750	29650	31550	9999	Platte County	Wyoming	0

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
WY	5603399999	56	33	NCNTY56033N56033	Sheridan County, WY	Sheridan County	78700	16750	19150	21550	23900	25850	27750	29650	31550	9999	Sheridan County	Wyoming	0
WY	5603599999	56	35	NCNTY56035N56035	Sublette County, WY	Sublette County	96800	20350	23250	26150	29050	31400	33700	36050	38350	9999	Sublette County	Wyoming	0
WY	5603799999	56	37	NCNTY56037N56037	Sweetwater County, WY	Sweetwater County	90200	18950	21650	24350	27050	29250	31400	33550	35750	9999	Sweetwater County	Wyoming	0
WY	5603999999	56	39	NCNTY56039N56039	Teton County, WY	Teton County	110700	23200	26500	29800	33100	35750	38400	41050	43700	9999	Teton County	Wyoming	0
WY	5604199999	56	41	NCNTY56041N56041	Uinta County, WY	Uinta County	69500	16750	19150	21550	23900	25850	27750	29650	31550	9999	Uinta County	Wyoming	0
WY	5604399999	56	43	NCNTY56043N56043	Washakie County, WY	Washakie County	70200	16750	19150	21550	23900	25850	27750	29650	31550	9999	Washakie County	Wyoming	0
WY	5604599999	56	45	NCNTY56045N56045	Weston County, WY	Weston County	85500	18000	20550	23100	25650	27750	29800	31850	33900	9999	Weston County	Wyoming	0
AS	6099999999	60	999	NCNTY60999N60999	American Samoa	American Samoa	31700	10150	11600	13050	14450	15650	16800	17950	19100		American Samoa	American Samoa	0
GU	6601099999	66	10	NCNTY66010N66010	Guam	Guam	65000	13650	15600	17550	19500	21100	22650	24200	25750	9999	Guam	Guam	0
MP	6999999999	69	999	NCNTY69999N69999	Northern Mariana Islands	Northern Mariana Islands	28800	10150	11600	13050	14450	15650	16800	17950	19100		Northern Mariana Islands	Northern Mariana Isl	0
PR	7200199999	72	1	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Adjuntas Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Adjuntas Municipio	Puerto Rico	0
PR	7200399999	72	3	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	Aguada Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	60	Aguada Municipio	Puerto Rico	1
PR	7200599999	72	5	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	Aguadilla Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	60	Aguadilla Municipio	Puerto Rico	1
PR	7200799999	72	7	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Aguas Buenas Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Aguas Buenas Municipio	Puerto Rico	1
PR	7200999999	72	9	METRO41980N72923	Barranquitas-Aibonito, PR HUD Metro FMR Area	Aibonito Municipio	19700	5050	5750	6450	7150	7750	8300	8900	9450	9999	Aibonito Municipio	Puerto Rico	1
PR	7201199999	72	11	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	Añasco Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	4840	Añasco Municipio	Puerto Rico	1
PR	7201399999	72	13	METRO11640MM0470	Arecibo, PR HUD Metro FMR Area	Arecibo Municipio	21900	5400	6200	6950	7700	8350	8950	9550	10200	470	Arecibo Municipio	Puerto Rico	1
PR	7201599999	72	15	METRO25020M25020	Guayama, PR MSA	Arroyo Municipio	18800	5150	5900	6650	7350	7950	8550	9150	9750	9999	Arroyo Municipio	Puerto Rico	1
PR	7201799999	72	17	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Barceloneta Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Barceloneta Municipio	Puerto Rico	1
PR	7201999999	72	19	METRO41980N72923	Barranquitas-Aibonito, PR HUD Metro FMR Area	Barranquitas Municipio	19700	5050	5750	6450	7150	7750	8300	8900	9450	9999	Barranquitas Municipio	Puerto Rico	1
PR	7202199999	72	21	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Bayamón Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Bayamón Municipio	Puerto Rico	1
PR	7202399999	72	23	METRO41900M41900	San German, PR MSA	Cabo Rojo Municipio	18200	5150	5850	6600	7300	7900	8500	9100	9650	4840	Cabo Rojo Municipio	Puerto Rico	1
PR	7202599999	72	25	METRO41980MM1310	Caguas, PR HUD Metro FMR Area	Caguas Municipio	25700	6200	7050	7950	8800	9550	10250	10950	11650	1310	Caguas Municipio	Puerto Rico	1
PR	7202799999	72	27	METRO11640MM0470	Arecibo, PR HUD Metro FMR Area	Camuy Municipio	21900	5400	6200	6950	7700	8350	8950	9550	10200	470	Camuy Municipio	Puerto Rico	1
PR	7202999999	72	29	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Canóvanas Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Canóvanas Municipio	Puerto Rico	1
PR	7203199999	72	31	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Carolina Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Carolina Municipio	Puerto Rico	1
PR	7203399999	72	33	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Cataño Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Cataño Municipio	Puerto Rico	1
PR	7203599999	72	35	METRO41980MM1310	Caguas, PR HUD Metro FMR Area	Cayey Municipio	25700	6200	7050	7950	8800	9550	10250	10950	11650	1310	Cayey Municipio	Puerto Rico	1
PR	7203799999	72	37	METRO41980M21940	Fajardo, PR HUD Metro FMR Area	Ceiba Municipio	26000	6200	7050	7950	8800	9550	10250	10950	11650	7440	Ceiba Municipio	Puerto Rico	1
PR	7203999999	72	39	METRO41980N72923	Barranquitas-Aibonito, PR HUD Metro FMR Area	Ciales Municipio	19700	5050	5750	6450	7150	7750	8300	8900	9450	9999	Ciales Municipio	Puerto Rico	1
PR	7204199999	72	41	METRO41980MM1310	Caguas, PR HUD Metro FMR Area	Cidra Municipio	25700	6200	7050	7950	8800	9550	10250	10950	11650	1310	Cidra Municipio	Puerto Rico	1
PR	7204399999	72	43	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Coamo Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Coamo Municipio	Puerto Rico	0
PR	7204599999	72	45	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Comerío Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Comerío Municipio	Puerto Rico	1
PR	7204799999	72	47	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Corozal Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Corozal Municipio	Puerto Rico	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
PR	7204999999	72	49	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Culebra Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Culebra Municipio	Puerto Rico	0
PR	7205199999	72	51	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Dorado Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Dorado Municipio	Puerto Rico	1
PR	7205399999	72	53	METRO41980M21940	Fajardo, PR HUD Metro FMR Area	Fajardo Municipio	26000	6200	7050	7950	8800	9550	10250	10950	11650	7440	Fajardo Municipio	Puerto Rico	1
PR	7205499999	72	54	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Florida Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Florida Municipio	Puerto Rico	1
PR	7205599999	72	55	METRO38660M49500	Yauco, PR HUD Metro FMR Area	Guánica Municipio	18800	5050	5750	6450	7150	7750	8300	8900	9450	9999	Guánica Municipio	Puerto Rico	1
PR	7205799999	72	57	METRO25020M25020	Guayama, PR MSA	Guayama Municipio	18800	5150	5900	6650	7350	7950	8550	9150	9750	9999	Guayama Municipio	Puerto Rico	1
PR	7205999999	72	59	METRO38660M49500	Yauco, PR HUD Metro FMR Area	Guayanilla Municipio	18800	5050	5750	6450	7150	7750	8300	8900	9450	6360	Guayanilla Municipio	Puerto Rico	1
PR	7206199999	72	61	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Guaynabo Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Guaynabo Municipio	Puerto Rico	1
PR	7206399999	72	63	METRO41980MM1310	Caguas, PR HUD Metro FMR Area	Gurabo Municipio	25700	6200	7050	7950	8800	9550	10250	10950	11650	1310	Gurabo Municipio	Puerto Rico	1
PR	7206599999	72	65	METRO11640MM0470	Arecibo, PR HUD Metro FMR Area	Hatillo Municipio	21900	5400	6200	6950	7700	8350	8950	9550	10200	470	Hatillo Municipio	Puerto Rico	1
PR	7206799999	72	67	METRO32420M32420	Mayagüez, PR MSA	Hormigueros Municipio	22700	5800	6600	7450	8250	8950	9600	10250	10900	4840	Hormigueros Municipio	Puerto Rico	1
PR	7206999999	72	69	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Humacao Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Humacao Municipio	Puerto Rico	1
PR	7207199999	72	71	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	Isabela Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	9999	Isabela Municipio	Puerto Rico	1
PR	7207399999	72	73	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Jayuya Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Jayuya Municipio	Puerto Rico	0
PR	7207599999	72	75	METRO38660M38660	Ponce, PR HUD Metro FMR Area	Juana Díaz Municipio	20500	5450	6200	7000	7750	8400	9000	9650	10250	6360	Juana Díaz Municipio	Puerto Rico	1
PR	7207799999	72	77	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Juncos Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Juncos Municipio	Puerto Rico	1
PR	7207999999	72	79	METRO41900M41900	San German, PR MSA	Lajas Municipio	18200	5150	5850	6600	7300	7900	8500	9100	9650	9999	Lajas Municipio	Puerto Rico	1
PR	7208199999	72	81	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	Lares Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	9999	Lares Municipio	Puerto Rico	1
PR	7208399999	72	83	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Las Marías Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Las Marías Municipio	Puerto Rico	0
PR	7208599999	72	85	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Las Piedras Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Las Piedras Municipio	Puerto Rico	1
PR	7208799999	72	87	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Loíza Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Loíza Municipio	Puerto Rico	1
PR	7208999999	72	89	METRO41980M21940	Fajardo, PR HUD Metro FMR Area	Luquillo Municipio	26000	6200	7050	7950	8800	9550	10250	10950	11650	7440	Luquillo Municipio	Puerto Rico	1
PR	7209199999	72	91	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Manatí Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Manatí Municipio	Puerto Rico	1
PR	7209399999	72	93	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Maricao Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Maricao Municipio	Puerto Rico	0
PR	7209599999	72	95	METRO41980N72923	Barranquitas-Aibonito, PR HUD Metro FMR Area	Maunabo Municipio	19700	5050	5750	6450	7150	7750	8300	8900	9450	9999	Maunabo Municipio	Puerto Rico	1
PR	7209799999	72	97	METRO32420M32420	Mayagüez, PR MSA	Mayagüez Municipio	22700	5800	6600	7450	8250	8950	9600	10250	10900	4840	Mayagüez Municipio	Puerto Rico	1
PR	7209999999	72	99	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	Moca Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	60	Moca Municipio	Puerto Rico	1
PR	7210199999	72	101	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Morovis Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Morovis Municipio	Puerto Rico	1
PR	7210399999	72	103	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Naguabo Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Naguabo Municipio	Puerto Rico	1
PR	7210599999	72	105	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Naranjito Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Naranjito Municipio	Puerto Rico	1

State_Alpha	fips2010	State	County	cbsasub	Metro_Area_Name	County_Name	median2020	l30_1	l30_2	l30_3	l30_4	l30_5	l30_6	l30_7	l30_8	MSA	county_town_name	state_name	metro
PR	7210799999	72	107	METRO41980N72923	Barranquitas-Aibonito, PR HUD Metro FMR Area	Orocovis Municipio	19700	5050	5750	6450	7150	7750	8300	8900	9450	9999	Orocovis Municipio	Puerto Rico	1
PR	7210999999	72	109	METRO25020M25020	Guayama, PR MSA	Patillas Municipio	18800	5150	5900	6650	7350	7950	8550	9150	9750	9999	Patillas Municipio	Puerto Rico	1
PR	7211199999	72	111	METRO38660M49500	Yauco, PR HUD Metro FMR Area	Peñuelas Municipio	18800	5050	5750	6450	7150	7750	8300	8900	9450	6360	Peñuelas Municipio	Puerto Rico	1
PR	7211399999	72	113	METRO38660M38660	Ponce, PR HUD Metro FMR Area	Ponce Municipio	20500	5450	6200	7000	7750	8400	9000	9650	10250	6360	Ponce Municipio	Puerto Rico	1
PR	7211599999	72	115	METRO11640N72923	Quebradillas Municipio, PR HUD Metro FMR Area	Quebradillas Municipio	20300	5150	5900	6650	7350	7950	8550	9150	9750	9999	Quebradillas Municipio	Puerto Rico	1
PR	7211799999	72	117	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	Rincón Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	9999	Rincón Municipio	Puerto Rico	1
PR	7211999999	72	119	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Río Grande Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Río Grande Municipio	Puerto Rico	1
PR	7212199999	72	121	METRO41900M41900	San German, PR MSA	Sabana Grande Municipio	18200	5150	5850	6600	7300	7900	8500	9100	9650	4840	Sabana Grande Municipio	Puerto Rico	1
PR	7212399999	72	123	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Salinas Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Salinas Municipio	Puerto Rico	0
PR	7212599999	72	125	METRO41900M41900	San German, PR MSA	San Germán Municipio	18200	5150	5850	6600	7300	7900	8500	9100	9650	4840	San Germán Municipio	Puerto Rico	1
PR	7212799999	72	127	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	San Juan Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	San Juan Municipio	Puerto Rico	1
PR	7212999999	72	129	METRO41980MM1310	Caguas, PR HUD Metro FMR Area	San Lorenzo Municipio	25700	6200	7050	7950	8800	9550	10250	10950	11650	1310	San Lorenzo Municipio	Puerto Rico	1
PR	7213199999	72	131	METRO10380M10380	Aguadilla-Isabela, PR HUD Metro FMR Area	San Sebastián Municipio	21500	5200	5950	6700	7400	8000	8600	9200	9800	9999	San Sebastián Municipio	Puerto Rico	1
PR	7213399999	72	133	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Santa Isabel Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Santa Isabel Municipio	Puerto Rico	0
PR	7213599999	72	135	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Toa Alta Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Toa Alta Municipio	Puerto Rico	1
PR	7213799999	72	137	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Toa Baja Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Toa Baja Municipio	Puerto Rico	1
PR	7213999999	72	139	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Trujillo Alto Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Trujillo Alto Municipio	Puerto Rico	1
PR	7214199999	72	141	METRO10380N72141	Utuado Municipio, PR HUD Metro FMR Area	Utuado Municipio	21100	5250	6000	6750	7450	8050	8650	9250	9850	9999	Utuado Municipio	Puerto Rico	1
PR	7214399999	72	143	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Vega Alta Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Vega Alta Municipio	Puerto Rico	1
PR	7214599999	72	145	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Vega Baja Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Vega Baja Municipio	Puerto Rico	1
PR	7214799999	72	147	NCNTY72923N72923	Puerto Rico HUD Nonmetro Area	Vieques Municipio	20300	5050	5750	6450	7150	7750	8300	8900	9450	9999	Vieques Municipio	Puerto Rico	0
PR	7214999999	72	149	METRO38660M38660	Ponce, PR HUD Metro FMR Area	Villalba Municipio	20500	5450	6200	7000	7750	8400	9000	9650	10250	6360	Villalba Municipio	Puerto Rico	1
PR	7215199999	72	151	METRO41980MM7440	San Juan-Guaynabo, PR HUD Metro FMR Area	Yabucoa Municipio	28800	6500	7400	8350	9250	10000	10750	11500	12250	7440	Yabucoa Municipio	Puerto Rico	1
PR	7215399999	72	153	METRO38660M49500	Yauco, PR HUD Metro FMR Area	Yauco Municipio	18800	5050	5750	6450	7150	7750	8300	8900	9450	6360	Yauco Municipio	Puerto Rico	1
VI	7801099999	78	10	NCNTY78010N78010	St. Croix Island, VI	St. Croix	53900	12200	13950	15700	17400	18800	20200	21600	23000	9999	St. Croix	Virgin Islands	0
VI	7802099999	78	20	NCNTY78020N78020	St. John Island, VI	St. John	65000	19100	21800	24550	27250	29450	31650	33800	36000	9999	St. John	Virgin Islands	0
VI	7803099999	78	30	NCNTY78030N78030	St. Thomas Island, VI	St. Thomas	60500	14150	16150	18150	20150	21800	23400	25000	26600	9999	St. Thomas	Virgin Islands	0

Attach. 11

STATE	PROGRAM	1 PERSON	2 PERSON	3 PERSON	4 PERSON	5 PERSON	6 PERSON	7 PERSON	8 PERSON
		I N C O M E L I M I T S							
ALABAMA									
FY 2020 MFI: 65300	30% OF MEDIAN	13700	15650	17650	19600	21150	22700	24300	25850
	VERY LOW INCOME	22850	26100	29400	32650	35250	37850	40500	43100
	LOW-INCOME	36550	41800	47000	52250	56400	60600	64800	68950
ALASKA									
FY 2020 MFI: 92200	30% OF MEDIAN	19350	22150	24900	27650	29850	32100	34300	36500
	VERY LOW INCOME	32250	36900	41500	46100	49800	53500	57150	60850
	LOW-INCOME	51650	59000	66400	73750	79650	85550	91450	97350
ARIZONA									
FY 2020 MFI: 72100	30% OF MEDIAN	15150	17300	19450	21650	23350	25100	26800	28550
	VERY LOW INCOME	25250	28850	32450	36050	38950	41800	44700	47600
	LOW-INCOME	40400	46150	51900	57700	62300	66900	71500	76150
ARKANSAS									
FY 2020 MFI: 61000	30% OF MEDIAN	12800	14650	16450	18300	19750	21250	22700	24150
	VERY LOW INCOME	21350	24400	27450	30500	32950	35400	37800	40250
	LOW-INCOME	34150	39050	43900	48800	52700	56600	60500	64400
CALIFORNIA									
FY 2020 MFI: 87100	30% OF MEDIAN	18300	20900	23500	26150	28200	30300	32400	34500
	VERY LOW INCOME	30500	34850	39200	43550	47050	50500	54000	57500
	LOW-INCOME	48800	55750	62700	69700	75250	80850	86400	92000
COLORADO									
FY 2020 MFI: 90200	30% OF MEDIAN	18950	21650	24350	27050	29200	31400	33550	35700
	VERY LOW INCOME	31550	36100	40600	45100	48700	52300	55900	59550
	LOW-INCOME	50500	57750	64950	72150	77950	83700	89500	95250
CONNECTICUT									
FY 2020 MFI: 99700	30% OF MEDIAN	21550	24600	27700	30800	33250	35700	38150	40650
	VERY LOW INCOME	35900	41050	46150	51300	55400	59500	63600	67700
	LOW-INCOME	54950	62800	70650	78500	84800	91050	97350	103600
DELAWARE									
FY 2020 MFI: 81900	30% OF MEDIAN	17200	19650	22100	24550	26550	28500	30450	32450
	VERY LOW INCOME	28650	32750	36850	40950	44250	47500	50800	54050
	LOW-INCOME	45850	52400	58950	65500	70750	76000	81250	86500
FLORIDA									
FY 2020 MFI: 68000	30% OF MEDIAN	14300	16300	18350	20400	22050	23650	25300	26950
	VERY LOW INCOME	23800	27200	30600	34000	36700	39450	42150	44900
	LOW-INCOME	38100	43500	48950	54400	58750	63100	67450	71800
GEORGIA									
FY 2020 MFI: 72200	30% OF MEDIAN	15150	17350	19500	21650	23400	25150	26850	28600
	VERY LOW INCOME	25250	28900	32500	36100	39000	41900	44750	47650
	LOW-INCOME	40450	46200	52000	57750	62400	67000	71600	76250
HAWAII									
FY 2020 MFI: 97100	30% OF MEDIAN	20400	23300	26200	29150	31450	33800	36100	38450
	VERY LOW INCOME	34000	38850	43700	48550	52450	56300	60200	64100
	LOW-INCOME	54400	62150	69900	77700	83900	90100	96300	102550

STATE	PROGRAM	1 PERSON	2 PERSON	3 PERSON	4 PERSON	5 PERSON	6 PERSON	7 PERSON	8 PERSON
IDAHO									
FY 2020 MFI: 68200	30% OF MEDIAN	14300	16350	18400	20450	22100	23750	25350	27000
	VERY LOW INCOME	23850	27300	30700	34100	36850	39550	42300	45000
	LOW-INCOME	38200	43650	49100	54550	58900	63300	67650	72000
ILLINOIS									
FY 2020 MFI: 84100	30% OF MEDIAN	17650	20200	22700	25250	27250	29250	31300	33300
	VERY LOW INCOME	29450	33650	37850	42050	45400	48800	52150	55500
	LOW-INCOME	47100	53800	60550	67300	72650	78050	83450	88800
INDIANA									
FY 2020 MFI: 72300	30% OF MEDIAN	15200	17350	19500	21700	23450	25150	26900	28650
	VERY LOW INCOME	25300	28900	32550	36150	39050	41950	44850	47700
	LOW-INCOME	40500	46250	52050	57850	62450	67100	71700	76350
IOWA									
FY 2020 MFI: 79700	30% OF MEDIAN	16750	19150	21500	23900	25800	27750	29650	31550
	VERY LOW INCOME	27900	31900	35850	39850	43050	46250	49400	52600
	LOW-INCOME	44650	51000	57400	63750	68850	73950	79050	84150
KANSAS									
FY 2020 MFI: 76500	30% OF MEDIAN	16050	18350	20650	22950	24800	26600	28450	30300
	VERY LOW INCOME	26800	30600	34450	38250	41300	44350	47450	50500
	LOW-INCOME	42850	48950	55100	61200	66100	71000	75900	80800
KENTUCKY									
FY 2020 MFI: 65400	30% OF MEDIAN	13750	15700	17650	19600	21200	22750	24350	25900
	VERY LOW INCOME	22900	26150	29450	32700	35300	37950	40550	43150
	LOW-INCOME	36600	41850	47100	52300	56500	60700	64900	69050
LOUISIANA									
FY 2020 MFI: 64300	30% OF MEDIAN	13500	15450	17350	19300	20850	22400	23900	25450
	VERY LOW INCOME	22500	25700	28950	32150	34700	37300	39850	42450
	LOW-INCOME	36000	41150	46300	51450	55550	59650	63800	67900
MAINE									
FY 2020 MFI: 76600	30% OF MEDIAN	16100	18400	20700	23000	24800	26650	28500	30350
	VERY LOW INCOME	26800	30650	34450	38300	41350	44450	47500	50550
	LOW-INCOME	42900	49000	55150	61300	66200	71100	76000	80900
MARYLAND									
FY 2020 MFI: 104500	30% OF MEDIAN	21950	25100	28200	31350	33850	36350	38850	41400
	VERY LOW INCOME	36600	41800	47050	52250	56450	60600	64800	68950
	LOW-INCOME	54950	62800	70650	78500	84800	91050	97350	103600
MASSACHUSETTS									
FY 2020 MFI: 104900	30% OF MEDIAN	22050	25200	28300	31450	34000	36500	39000	41550
	VERY LOW INCOME	36700	41950	47200	52450	56650	60850	65050	69250
	LOW-INCOME	54950	62800	70650	78500	84800	91050	97350	103600
MICHIGAN									
FY 2020 MFI: 74000	30% OF MEDIAN	15550	17750	20000	22200	24000	25750	27550	29300
	VERY LOW INCOME	25900	29600	33300	37000	39950	42900	45900	48850
	LOW-INCOME	41450	47350	53300	59200	63950	68650	73400	78150

STATE	PROGRAM	1 PERSON	2 PERSON	3 PERSON	4 PERSON	5 PERSON	6 PERSON	7 PERSON	8 PERSON
		I N C O M E L I M I T S							
MINNESOTA									
FY 2020 MFI: 91800	30% OF MEDIAN	19300	22050	24800	27550	29750	31950	34150	36350
	VERY LOW INCOME	32150	36700	41300	45900	49550	53250	56900	60600
	LOW-INCOME	51400	58750	66100	73450	79300	85200	91050	96950
MISSISSIPPI									
FY 2020 MFI: 59400	30% OF MEDIAN	12450	14250	16050	17800	19250	20650	22100	23500
	VERY LOW INCOME	20800	23750	26750	29700	32100	34450	36850	39200
	LOW-INCOME	33250	38000	42750	47500	51300	55100	58900	62750
MISSOURI									
FY 2020 MFI: 71500	30% OF MEDIAN	15000	17150	19300	21450	23150	24900	26600	28300
	VERY LOW INCOME	25050	28600	32200	35750	38600	41450	44350	47200
	LOW-INCOME	40050	45750	51500	57200	61800	66350	70950	75500
MONTANA									
FY 2020 MFI: 73300	30% OF MEDIAN	15400	17600	19800	22000	23750	25500	27250	29050
	VERY LOW INCOME	25650	29300	33000	36650	39600	42500	45450	48400
	LOW-INCOME	41050	46900	52800	58650	63350	68000	72700	77400
NEBRASKA									
FY 2020 MFI: 79800	30% OF MEDIAN	16750	19150	21550	23950	25850	27750	29700	31600
	VERY LOW INCOME	27950	31900	35900	39900	43100	46300	49500	52650
	LOW-INCOME	44700	51050	57450	63850	68950	74050	79150	84250
NEVADA									
FY 2020 MFI: 72500	30% OF MEDIAN	15750	18000	20250	22500	24300	26100	27900	29700
	VERY LOW INCOME	26250	30000	33750	37500	40500	43500	46500	49500
	LOW-INCOME	42000	48000	54000	60000	64800	69600	74400	79200
NEW HAMPSHIRE									
FY 2020 MFI: 96700	30% OF MEDIAN	20300	23200	26100	29000	31350	33650	35950	38300
	VERY LOW INCOME	33850	38700	43500	48350	52200	56100	59950	63800
	LOW-INCOME	54150	61900	69600	77350	83550	89750	95950	102100
NEW JERSEY									
FY 2020 MFI: 103300	30% OF MEDIAN	21700	24800	27900	31000	33450	35950	38450	40900
	VERY LOW INCOME	36150	41300	46500	51650	55800	59900	64050	68200
	LOW-INCOME	54950	62800	70650	78500	84800	91050	97350	103600
NEW MEXICO									
FY 2020 MFI: 61900	30% OF MEDIAN	13000	14850	16700	18550	20050	21550	23050	24500
	VERY LOW INCOME	21650	24750	27850	30950	33450	35900	38400	40850
	LOW-INCOME	34650	39600	44550	49500	53500	57450	61400	65350
NEW YORK									
FY 2020 MFI: 85100	30% OF MEDIAN	17850	20400	23000	25550	27550	29600	31650	33700
	VERY LOW INCOME	29800	34050	38300	42550	45950	49350	52750	56150
	LOW-INCOME	47650	54450	61250	68100	73550	78950	84400	89850
NORTH CAROLINA									
FY 2020 MFI: 70000	30% OF MEDIAN	14700	16800	18900	21000	22700	24350	26050	27700
	VERY LOW INCOME	24500	28000	31500	35000	37800	40600	43400	46200
	LOW-INCOME	39200	44800	50400	56000	60500	64950	69450	73900

STATE	PROGRAM	1 PERSON	2 PERSON	3 PERSON	4 PERSON	5 PERSON	6 PERSON	7 PERSON	8 PERSON
		INCOME LIMITS							
NORTH DAKOTA									
FY 2020 MFI: 86900	30% OF MEDIAN	18250	20850	23450	26050	28150	30250	32350	34400
	VERY LOW INCOME	30400	34750	39100	43450	46950	50400	53900	57350
	LOW-INCOME	48650	55600	62550	69500	75100	80650	86200	91750
OHIO									
FY 2020 MFI: 73900	30% OF MEDIAN	15500	17750	19950	22150	23950	25700	27500	29250
	VERY LOW INCOME	25850	29550	33250	36950	39900	42850	45800	48750
	LOW-INCOME	41400	47300	53200	59100	63850	68600	73300	78050
OKLAHOMA									
FY 2020 MFI: 65300	30% OF MEDIAN	13700	15650	17650	19600	21150	22700	24300	25850
	VERY LOW INCOME	22850	26100	29400	32650	35250	37850	40500	43100
	LOW-INCOME	36550	41800	47000	52250	56400	60600	64800	68950
OREGON									
FY 2020 MFI: 77700	30% OF MEDIAN	16300	18650	21000	23300	25150	27050	28900	30750
	VERY LOW INCOME	27200	31100	34950	38850	41950	45050	48150	51300
	LOW-INCOME	43500	49750	55950	62150	67150	72100	77100	82050
PENNSYLVANIA									
FY 2020 MFI: 80700	30% OF MEDIAN	16950	19350	21800	24200	26150	28100	30000	31950
	VERY LOW INCOME	28250	32300	36300	40350	43600	46800	50050	53250
	LOW-INCOME	45200	51650	58100	64550	69700	74900	80050	85200
RHODE ISLAND									
FY 2020 MFI: 89800	30% OF MEDIAN	18850	21550	24250	26950	29100	31250	33400	35550
	VERY LOW INCOME	31450	35900	40400	44900	48500	52100	55700	59250
	LOW-INCOME	50300	57450	64650	71850	77600	83350	89100	94850
SOUTH CAROLINA									
FY 2020 MFI: 66300	30% OF MEDIAN	13900	15900	17900	19900	21500	23050	24650	26250
	VERY LOW INCOME	23200	26500	29850	33150	35800	38450	41100	43750
	LOW-INCOME	37150	42450	47750	53050	57300	61550	65750	70000
SOUTH DAKOTA									
FY 2020 MFI: 77800	30% OF MEDIAN	16350	18650	21000	23350	25200	27050	28950	30800
	VERY LOW INCOME	27250	31100	35000	38900	42000	45100	48250	51350
	LOW-INCOME	43550	49800	56000	62250	67200	72200	77200	82150
TENNESSEE									
FY 2020 MFI: 66800	30% OF MEDIAN	14050	16050	18050	20050	21650	23250	24850	26450
	VERY LOW INCOME	23400	26700	30050	33400	36050	38750	41400	44100
	LOW-INCOME	37400	42750	48100	53450	57700	62000	66250	70550
TEXAS									
FY 2020 MFI: 74500	30% OF MEDIAN	15650	17900	20100	22350	24150	25950	27700	29500
	VERY LOW INCOME	26100	29800	33550	37250	40250	43200	46200	49150
	LOW-INCOME	41700	47700	53650	59600	64350	69150	73900	78650
UTAH									
FY 2020 MFI: 82800	30% OF MEDIAN	17400	19850	22350	24850	26850	28800	30800	32800
	VERY LOW INCOME	29000	33100	37250	41400	44700	48000	51350	54650
	LOW-INCOME	46350	53000	59600	66250	71550	76850	82150	87450

STATE	PROGRAM	1 PERSON	2 PERSON	3 PERSON	4 PERSON	5 PERSON	6 PERSON	7 PERSON	8 PERSON
		I N C O M E L I M I T S							
VERMONT									
FY 2020 MFI: 79000	30% OF MEDIAN	16600	18950	21350	23700	25600	27500	29400	31300
	VERY LOW INCOME	27650	31600	35550	39500	42650	45800	49000	52150
	LOW-INCOME	44250	50550	56900	63200	68250	73300	78350	83400
VIRGINIA									
FY 2020 MFI: 91600	30% OF MEDIAN	19250	22000	24750	27500	29700	31900	34100	36250
	VERY LOW INCOME	32050	36650	41200	45800	49450	53150	56800	60450
	LOW-INCOME	51300	58600	65950	73300	79150	85000	90850	96750
WASHINGTON									
FY 2020 MFI: 89800	30% OF MEDIAN	18850	21550	24250	26950	29100	31250	33400	35550
	VERY LOW INCOME	31450	35900	40400	44900	48500	52100	55700	59250
	LOW-INCOME	50300	57450	64650	71850	77600	83350	89100	94850
WEST VIRGINIA									
FY 2020 MFI: 59600	30% OF MEDIAN	12500	14300	16100	17900	19300	20750	22150	23600
	VERY LOW INCOME	20850	23850	26800	29800	32200	34550	36950	39350
	LOW-INCOME	33400	38150	42900	47700	51500	55300	59100	62950
WISCONSIN									
FY 2020 MFI: 80100	30% OF MEDIAN	16800	19200	21650	24050	25950	27850	29800	31700
	VERY LOW INCOME	28050	32050	36050	40050	43250	46450	49650	52850
	LOW-INCOME	44850	51250	57650	64100	69200	74350	79450	84600
WYOMING									
FY 2020 MFI: 79500	30% OF MEDIAN	16750	19150	21500	23900	25800	27750	29650	31550
	VERY LOW INCOME	27900	31900	35850	39850	43050	46250	49400	52600
	LOW-INCOME	44650	51000	57400	63750	68850	73950	79050	84150
US									
FY 2020 MFI: 78500	30% OF MEDIAN	16500	18850	21200	23550	25450	27300	29200	31100
	VERY LOW INCOME	27500	31400	35350	39250	42400	45550	48650	51800
	LOW-INCOME	43950	50250	56500	62800	67800	72850	77850	82900

Attach. 12

United States Census Bureau

QuickFacts
California

QuickFacts provides statistics for all states and counties, and for cities and towns with a ***population of 5,000 or more***.

Table

All Topics	California
Foreign born persons, percent, 2015-2019	**26.8%**
PEOPLE	
Population	
Population Estimates, July 1 2021, (V2021)	39,237,836
Population estimates base, April 1, 2020, (V2021)	39,538,223
Population, percent change - April 1, 2020 (estimates base) to July 1, 2021, (V2021)	-0.8%
Population, Census, April 1, 2020	39,538,223
Population, Census, April 1, 2010	37,253,956
Age and Sex	
Persons under 5 years, percent	6.0%
Persons under 18 years, percent	22.5%
Persons 65 years and over, percent	14.8%
Female persons, percent	50.3%
Race and Hispanic Origin	
White alone, percent	71.9%
Black or African American alone, percent (a)	6.5%
American Indian and Alaska Native alone, percent (a)	1.6%
Asian alone, percent (a)	15.5%
Native Hawaiian and Other Pacific Islander alone, percent (a)	0.5%
Two or More Races, percent	4.0%
Hispanic or Latino, percent (b)	39.4%
White alone, not Hispanic or Latino, percent	36.5%
Population Characteristics	
Veterans, 2015-2019	1,574,531
Foreign born persons, percent, 2015-2019	**26.8%**
Housing	
Housing units, July 1, 2019, (V2019)	14,366,336
Owner-occupied housing unit rate, 2015-2019	54.8%
Median value of owner-occupied housing units, 2015-2019	$505,000
Median selected monthly owner costs -with a mortgage, 2015-2019	$2,357
Median selected monthly owner costs -without a mortgage, 2015-2019	$594
Median gross rent, 2015-2019	$1,503
Building permits, 2020	106,075
Families & Living Arrangements	
Households, 2015-2019	13,044,266
Persons per household, 2015-2019	2.95
Living in same house 1 year ago, percent of persons age 1 year+, 2015-2019	87.1%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	44.2%
Computer and Internet Use	
Households with a computer, percent, 2015-2019	93.0%
Households with a broadband Internet subscription, percent, 2015-2019	86.7%
Education	
High school graduate or higher, percent of persons age 25 years+, 2015-2019	83.3%
Bachelor's degree or higher, percent of persons age 25 years+, 2015-2019	33.9%
Health	
With a disability, under age 65 years, percent, 2015-2019	6.7%
Persons without health insurance, under age 65 years, percent	8.9%
Economy	
In civilian labor force, total, percent of population age 16 years+, 2015-2019	63.3%

In civilian labor force, female, percent of population age 16 years+, 2015-2019	57.5%
Total accommodation and food services sales, 2012 ($1,000) (c)	90,830,372
Total health care and social assistance receipts/revenue, 2012 ($1,000) (c)	248,953,592
Total manufacturers shipments, 2012 ($1,000) (c)	512,303,164
Total retail sales, 2012 ($1,000) (c)	481,800,461
Total retail sales per capita, 2012 (c)	$12,665
Transportation	
Mean travel time to work (minutes), workers age 16 years+, 2015-2019	29.8
Income & Poverty	
Median household income (in 2019 dollars), 2015-2019	$75,235
Per capita income in past 12 months (in 2019 dollars), 2015-2019	$36,955
Persons in poverty, percent	11.5%

BUSINESSES

Businesses	
Total employer establishments, 2019	966,224
Total employment, 2019	15,516,824
Total annual payroll, 2019 ($1,000)	1,077,175,621
Total employment, percent change, 2018-2019	1.9%
Total nonemployer establishments, 2018	3,453,769
All firms, 2012	3,548,449
Men-owned firms, 2012	1,852,580
Women-owned firms, 2012	1,320,085
Minority-owned firms, 2012	1,619,857
Nonminority-owned firms, 2012	1,819,107
Veteran-owned firms, 2012	252,377
Nonveteran-owned firms, 2012	3,176,341

GEOGRAPHY

Geography	
Population per square mile, 2010	239.1
Land area in square miles, 2010	155,779.22
FIPS Code	06

About datasets used in this table

Value Notes

Estimates are not comparable to other geographic levels due to methodology differences that may exist between different data sources.

Some estimates presented here come from sample data, and thus have sampling errors that may render some apparent differences between geographies statistically indistinguishable. Click the Quick Info icon to the row in TABLE view to learn about sampling error.

The vintage year (e.g., V2021) refers to the final year of the series (2020 thru 2021). Different vintage years of estimates are not comparable.

Fact Notes

- **(a)** Includes persons reporting only one race
- **(c)** Economic Census - Puerto Rico data are not comparable to U.S. Economic Census data
- **(b)** Hispanics may be of any race, so also are included in applicable race categories

Value Flags

- **-** Either no or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest or upper in open ended distribution.
- **F** Fewer than 25 firms
- **D** Suppressed to avoid disclosure of confidential information
- **N** Data for this geographic area cannot be displayed because the number of sample cases is too small.
- **FN** Footnote on this item in place of data
- **X** Not applicable
- **S** Suppressed; does not meet publication standards
- **NA** Not available
- **Z** Value greater than zero but less than half unit of measure shown

QuickFacts data are derived from: Population Estimates, American Community Survey, Census of Population and Housing, Current Population Survey, Small Area Health Insurance Estimates, Small Area Income and P Estimates, State and County Housing Unit Estimates, County Business Patterns, Nonemployer Statistics, Economic Census, Survey of Business Owners, Building Permits.

QuickFacts

Fresno County, California; Tulare County, California; Kings County, California; Kern County, California

QuickFacts provides statistics for all states and counties, and for cities and towns with a ***population of 5,000 or more***.

Table

All Topics	Fresno County, California	Tulare County, California	Kings County, California	Kern County, California
Foreign born persons, percent, 2015-2019	**21.2%**	**21.8%**	**18.9%**	**19.9%**
PEOPLE				
Population				
Population Estimates, July 1 2021, (V2021)	NA	NA	NA	NA
Population estimates base, April 1, 2020, (V2021)	NA	NA	NA	NA
Population, percent change - April 1, 2020 (estimates base) to July 1, 2021, (V2021)	NA	NA	NA	NA
Population, Census, April 1, 2020	1,008,654	473,117	152,486	909,235
Population, Census, April 1, 2010	930,450	442,179	152,982	839,631
Age and Sex				
Persons under 5 years, percent	7.6%	7.8%	7.6%	7.6%
Persons under 18 years, percent	28.2%	30.5%	27.0%	28.8%
Persons 65 years and over, percent	12.6%	11.6%	10.5%	11.2%
Female persons, percent	50.1%	50.0%	44.9%	48.8%
Race and Hispanic Origin				
White alone, percent	76.6%	88.2%	80.8%	82.3%
Black or African American alone, percent (a)	5.8%	2.2%	7.5%	6.3%
American Indian and Alaska Native alone, percent (a)	3.0%	2.8%	3.2%	2.6%
Asian alone, percent (a)	11.1%	4.0%	4.4%	5.4%
Native Hawaiian and Other Pacific Islander alone, percent (a)	0.3%	0.2%	0.4%	0.3%
Two or More Races, percent	3.2%	2.7%	3.7%	3.2%
Hispanic or Latino, percent (b)	53.8%	65.6%	55.3%	54.6%
White alone, not Hispanic or Latino, percent	28.6%	27.7%	31.3%	32.8%
Population Characteristics				
Veterans, 2015-2019	36,125	14,633	9,684	35,594
Foreign born persons, percent, 2015-2019	**21.2%**	**21.8%**	**18.9%**	**19.9%**
Housing				
Housing units, July 1, 2019, (V2019)	336,473	151,603	46,965	302,898
Owner-occupied housing unit rate, 2015-2019	53.3%	57.1%	52.3%	58.3%
Median value of owner-occupied housing units, 2015-2019	$255,000	$205,000	$215,900	$213,900
Median selected monthly owner costs -with a mortgage, 2015-2019	$1,631	$1,420	$1,459	$1,527
Median selected monthly owner costs -without a mortgage, 2015-2019	$484	$421	$446	$452
Median gross rent, 2015-2019	$998	$942	$990	$978
Building permits, 2020	3,130	1,575	306	2,502
Families & Living Arrangements				
Households, 2015-2019	307,906	138,238	43,452	270,282
Persons per household, 2015-2019	3.14	3.30	3.13	3.17
Living in same house 1 year ago, percent of persons age 1 year+, 2015-2019	85.8%	88.6%	81.9%	86.1%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	44.6%	51.3%	41.5%	44.2%
Computer and Internet Use				
Households with a computer, percent, 2015-2019	89.2%	87.6%	90.5%	87.5%
Households with a broadband Internet subscription, percent, 2015-2019	80.2%	77.7%	80.4%	79.7%
Education				
High school graduate or higher, percent of persons age 25 years+, 2015-2019	76.0%	70.8%	73.4%	74.1%
Bachelor's degree or higher, percent of persons age 25 years+, 2015-2019	21.2%	14.6%	14.7%	16.4%

Health				
With a disability, under age 65 years, percent, 2015-2019	9.2%	8.2%	8.6%	7.8%
Persons without health insurance, under age 65 years, percent	⚠ 9.7%	⚠ 9.5%	⚠ 9.4%	⚠ 9.3%
Economy				
In civilian labor force, total, percent of population age 16 years+, 2015-2019	60.9%	59.0%	51.8%	58.0%
In civilian labor force, female, percent of population age 16 years+, 2015-2019	55.2%	51.1%	51.5%	52.4%
Total accommodation and food services sales, 2012 ($1,000) (c)	1,226,169	451,880	378,595	1,092,151
Total health care and social assistance receipts/revenue, 2012 ($1,000) (c)	5,325,615	1,610,236	587,818	3,675,000
Total manufacturers shipments, 2012 ($1,000) (c)	8,658,325	8,362,447	2,904,014	6,890,714
Total retail sales, 2012 ($1,000) (c)	9,117,752	3,903,527	1,031,953	8,640,550
Total retail sales per capita, 2012 (c)	$9,619	$8,637	$6,818	$10,092
Transportation				
Mean travel time to work (minutes), workers age 16 years+, 2015-2019	23.1	22.6	22.8	23.3
Income & Poverty				
Median household income (in 2019 dollars), 2015-2019	$53,969	$49,687	$57,848	$53,350
Per capita income in past 12 months (in 2019 dollars), 2015-2019	$24,422	$21,380	$22,373	$23,326
Persons in poverty, percent	⚠ 17.1%	⚠ 17.1%	⚠ 14.5%	⚠ 18.3%

BUSINESSES

Businesses				
Total employer establishments, 2019	17,351	6,531	1,682	13,197
Total employment, 2019	277,632	99,961	25,541	199,982
Total annual payroll, 2019 ($1,000)	12,530,805	4,148,897	1,065,825	9,521,255
Total employment, percent change, 2018-2019	2.6%	2.3%	-2.9%	1.5%
Total nonemployer establishments, 2018	55,668	21,098	5,119	49,553
All firms, 2012	59,569	23,310	6,091	51,393
Men-owned firms, 2012	30,341	12,168	3,083	25,177
Women-owned firms, 2012	22,727	8,115	2,112	20,004
Minority-owned firms, 2012	30,912	11,023	2,862	26,610
Nonminority-owned firms, 2012	26,343	11,406	2,876	23,006
Veteran-owned firms, 2012	4,556	1,677	691	3,770
Nonveteran-owned firms, 2012	51,988	20,452	5,039	45,383

GEOGRAPHY

Geography				
Population per square mile, 2010	156.2	91.7	110.1	103.3
Land area in square miles, 2010	5,957.99	4,824.22	1,389.42	8,131.92
FIPS Code	06019	06107	06031	06029

About datasets used in this table

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Fact Notes

(a) Includes persons reporting only one race
(c) Economic Census - Puerto Rico data are not comparable to U.S. Economic Census data
(b) Hispanics may be of any race, so also are included in applicable race categories

Value Flags

- Either no or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest or upper in open ended distribution.
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United States Census Bureau

QuickFacts

San Joaquin County, California; Stanislaus County, California; Merced County, California; Madera County, California

QuickFacts provides statistics for all states and counties, and for cities and towns with a ***population of 5,000 or more***.

Table

All Topics	San Joaquin County, California	Stanislaus County, California	Merced County, California	Madera County, California
Foreign born persons, percent, 2015-2019	**23.3%**	**20.3%**	**26.3%**	**20.2%**
PEOPLE				
Population				
Population Estimates, July 1 2021, (V2021)	NA	NA	NA	NA
Population estimates base, April 1, 2020, (V2021)	NA	NA	NA	NA
Population, percent change - April 1, 2020 (estimates base) to July 1, 2021, (V2021)	NA	NA	NA	NA
Population, Census, April 1, 2020	779,233	552,878	281,202	156,255
Population, Census, April 1, 2010	685,306	514,453	255,793	150,865
Age and Sex				
Persons under 5 years, percent	6.9%	7.1%	7.7%	7.3%
Persons under 18 years, percent	26.8%	27.0%	29.3%	27.4%
Persons 65 years and over, percent	13.1%	13.4%	11.4%	14.3%
Female persons, percent	50.1%	50.4%	49.5%	51.8%
Race and Hispanic Origin				
White alone, percent	66.1%	83.3%	82.2%	85.9%
Black or African American alone, percent (a)	8.3%	3.5%	3.9%	4.2%
American Indian and Alaska Native alone, percent (a)	2.0%	2.0%	2.5%	4.4%
Asian alone, percent (a)	17.4%	6.1%	7.8%	2.6%
Native Hawaiian and Other Pacific Islander alone, percent (a)	0.8%	0.9%	0.4%	0.3%
Two or More Races, percent	5.5%	4.2%	3.2%	2.6%
Hispanic or Latino, percent (b)	42.0%	47.6%	61.0%	58.8%
White alone, not Hispanic or Latino, percent	30.5%	40.4%	26.5%	33.2%
Population Characteristics				
Veterans, 2015-2019	29,013	21,051	9,225	6,317
Foreign born persons, percent, 2015-2019	**23.3%**	**20.3%**	**26.3%**	**20.2%**
Housing				
Housing units, July 1, 2019, (V2019)	248,636	182,978	86,388	51,438
Owner-occupied housing unit rate, 2015-2019	56.6%	57.8%	52.2%	64.1%
Median value of owner-occupied housing units, 2015-2019	$342,100	$291,600	$252,700	$251,200
Median selected monthly owner costs -with a mortgage, 2015-2019	$1,907	$1,702	$1,493	$1,551
Median selected monthly owner costs -without a mortgage, 2015-2019	$523	$503	$460	$478
Median gross rent, 2015-2019	$1,208	$1,155	$1,021	$1,014
Building permits, 2020	3,914	552	1,019	852
Families & Living Arrangements				
Households, 2015-2019	228,567	173,898	80,008	44,881
Persons per household, 2015-2019	3.17	3.09	3.32	3.28
Living in same house 1 year ago, percent of persons age 1 year+, 2015-2019	86.8%	87.9%	86.6%	87.9%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	40.9%	42.9%	53.3%	45.3%
Computer and Internet Use				
Households with a computer, percent, 2015-2019	91.0%	91.6%	91.1%	89.8%
Households with a broadband Internet subscription, percent, 2015-2019	82.9%	84.8%	83.9%	79.9%
Education				
High school graduate or higher, percent of persons age 25 years+, 2015-2019	79.3%	78.9%	69.1%	71.9%
Bachelor's degree or higher, percent of persons age 25 years+, 2015-2019	18.8%	17.1%	13.8%	14.6%

Health				
With a disability, under age 65 years, percent, 2015-2019	8.7%	9.0%	9.1%	8.7%
Persons without health insurance, under age 65 years, percent	⚠ 8.2%	⚠ 8.4%	⚠ 11.4%	⚠ 11.0%
Economy				
In civilian labor force, total, percent of population age 16 years+, 2015-2019	60.3%	60.9%	59.6%	54.3%
In civilian labor force, female, percent of population age 16 years+, 2015-2019	53.6%	53.4%	51.0%	47.9%
Total accommodation and food services sales, 2012 ($1,000) (c)	808,606	705,698	232,910	150,065
Total health care and social assistance receipts/revenue, 2012 ($1,000) (c)	3,447,722	3,634,960	788,114	760,956
Total manufacturers shipments, 2012 ($1,000) (c)	9,212,428	11,703,620	4,435,633	1,441,125
Total retail sales, 2012 ($1,000) (c)	7,059,491	5,933,581	1,959,473	1,012,856
Total retail sales per capita, 2012 (c)	$10,047	$11,373	$7,470	$6,654
Transportation				
Mean travel time to work (minutes), workers age 16 years+, 2015-2019	34.2	29.9	28.6	28.3
Income & Poverty				
Median household income (in 2019 dollars), 2015-2019	$64,432	$60,704	$53,672	$57,585
Per capita income in past 12 months (in 2019 dollars), 2015-2019	$27,521	$26,258	$23,011	$22,853
Persons in poverty, percent	⚠ 13.9%	⚠ 13.0%	⚠ 16.3%	⚠ 14.1%
BUSINESSES				
Businesses				
Total employer establishments, 2019	11,989	9,279	3,177	2,039
Total employment, 2019	195,234	145,805	46,799	27,690
Total annual payroll, 2019 ($1,000)	9,144,028	7,026,189	1,883,107	1,308,125
Total employment, percent change, 2018-2019	0.2%	0.5%	1.6%	2.0%
Total nonemployer establishments, 2018	42,899	30,181	11,717	7,504
All firms, 2012	41,940	33,036	12,848	8,094
Men-owned firms, 2012	21,962	16,930	7,163	3,888
Women-owned firms, 2012	14,941	11,455	4,071	3,202
Minority-owned firms, 2012	20,472	13,341	6,912	3,203
Nonminority-owned firms, 2012	19,915	18,348	5,448	4,524
Veteran-owned firms, 2012	3,449	2,914	1,060	618
Nonveteran-owned firms, 2012	36,663	28,584	11,149	7,044
GEOGRAPHY				
Geography				
Population per square mile, 2010	492.6	344.2	132.2	70.6
Land area in square miles, 2010	1,391.32	1,494.83	1,934.97	2,137.07
FIPS Code	06077	06099	06047	06039

About datasets used in this table

Value Notes

Estimates are not comparable to other geographic levels due to methodology differences that may exist between different data sources.

Some estimates presented here come from sample data, and thus have sampling errors that may render some apparent differences between geographies statistically indistinguishable. Click the Quick Info icon to the row in TABLE view to learn about sampling error.

The vintage year (e.g., V2021) refers to the final year of the series (2020 thru 2021). Different vintage years of estimates are not comparable.

Fact Notes

- **(a)** Includes persons reporting only one race
- **(c)** Economic Census - Puerto Rico data are not comparable to U.S. Economic Census data
- **(b)** Hispanics may be of any race, so also are included in applicable race categories

Value Flags

- **-** Either no or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest or upper in open ended distribution.
- **F** Fewer than 25 firms
- **D** Suppressed to avoid disclosure of confidential information
- **N** Data for this geographic area cannot be displayed because the number of sample cases is too small.
- **FN** Footnote on this item in place of data
- **X** Not applicable
- **S** Suppressed; does not meet publication standards
- **NA** Not available
- **Z** Value greater than zero but less than half unit of measure shown

QuickFacts data are derived from: Population Estimates, American Community Survey, Census of Population and Housing, Current Population Survey, Small Area Health Insurance Estimates, Small Area Income and P Estimates, State and County Housing Unit Estimates, County Business Patterns, Nonemployer Statistics, Economic Census, Survey of Business Owners, Building Permits.

Attach. 13

	NOx	SOx	PM10	CO	VOC	PM2.5	MW/hour	% of Avenal Electricity
One Digester (lbs/year)	9,166	2,268	3,970	101,636	6,370	3970	1.059	
One Digester (tons/year)	4.58	1.13	1.99	50.82	3.19	1.99		
25 Digesters (lbs/year)	229,150	56,700	99,250	2,540,900	159,250	99,250	26.475	4.41%
25 Digesters (tons/year)	114.58	28.35	49.63	1,270.45	79.63	49.63		
Avenal (lbs/year)	198,840	33,521	161,550	197,928	69,222	161550	600	
Avenal (tons/year)	99.42	16.76	80.78	98.96	34.61	80.775		
Pollution Difference Digesters vs. Avenal (tons/year)	15.16	11.59	-31.15	1,171.49	45.01	-31.15		

Source: Lakeview Dairy Biogas digester Authority to Construct Permit March 22, 2016, Post-Project Stationary Source Potential to Emit (SSPE2) at 14, 20

Source: Avenal Power Center Authority to Construct Permit No. December 17, 2010, Post-Project Stationary Source Potential to Emit (SSPE2) at 27.

Attach. 14

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Jim Rexroad
Avenal Power Center LLC
500 Dallas Street, Level 31
Houston, TX 77002

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rexroad:

Enclosed is the District's final determination of compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the PDOC were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

cc: Gary Rubenstein, Sierra Research

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Tollstrup:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

www.valleyair.org www.healthyairliving.com

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Gerardo C. Rios (AIR 3)
Chief, Permits Office
Air Division
U.S. E.P.A. - Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rios:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

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The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Joseph Douglas
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Douglas:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

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Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Avenal Power Center LLC for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies and other interested parties. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1100751 is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

Avenal Power Center Project
California Energy Commission
Application for Certification Docket #: 08-AFC-01

Facility Name:	Avenal Power Center, LLC
Mailing Address:	500 Dallas Street, Level 31 Houston, TX 77002
Contact Name:	Jim Rexroad
Telephone:	(713) 275-6147
Fax:	(713) 275-6115
Cell:	(832) 748-1060
E-Mail:	jim.Rexroad@macquarie.com
Alternate Contact:	Eric Walther
Telephone:	(916) 444-6666
Fax:	(916) 444-8373
Cell:	(916) 883-8774
E-Mail:	ewalther@sierraresearch.com
Alternate Contact:	Tracey Gilliland
Telephone:	(713) 275-6148
Cell:	(512) 217-3002
E-Mail:	tracey.gilliland@macquarie.com
Engineer:	Derek Fukuda, Air Quality Engineer
Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Project #:	C-1100751
Application #'s:	C-3953-10-1, C-3953-11-1, C-3953-12-1, C-3953-13-1, and C-3953-14-1
Submitted:	March 3, 2010

Table of Contents

I. PROPOSAL:

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 564 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

While Avenal Power Center, LLC has already received a Determination of Compliance for the above described facility, they are now proposing to limit the annual facility wide NO_X emissions from 288,618 lb/year to 198,840 lb/year, and the annual facility wide CO emissions from 1,205,418 lb/year to 197,928 lb/year. The effect of these limits will be two-fold: one, should the facility operate to its full permitted extent, it will have the lowest annual average permitted emissions of NO_X (0.045 lb-NOx/MWh) and CO (0.044 lb-CO/MWh) of any natural gas fired power plant known to the District; and two, the facility will be limited to less than the 100 tons/year major source thresholds of the federal prevention of significant deterioration program.

The Avenal Energy Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

The facility submitted an application to revise their existing DOC issued under Project C-1080386. This revision consists of limiting the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year. The equipment the DOC was issued for in project C-1080386 has not been implemented. All units in this project will be treated as new emissions units.

II. APPLICABLE RULES:

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 1100 Equipment Breakdown (12/17/92)
Rule 2010 Permits Required (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 2540 Acid Rain Program (11/13/97)

Rule 2550	Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001	New Source Performance Standards (4/14/99) Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units Subpart GG - Standards of Performance for Stationary Gas Turbines Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines Subpart JJJJ -Standards of Performance for Stationary Spark Ignition Internal Combustion Engines Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/2004) Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter Emission Rate (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
Rule 4351	Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
Rule 4701	Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702	Stationary Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703	Stationary Gas Turbines (9/20/07)
Rule 4801	Sulfur Compounds (12/17/92)
Rule 8011	General Requirements (8/19/04)
Rule 8021	Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031	Bulk Materials (8/19/04)
Rule 8041	Carryout and Trackout (8/19/04)
Rule 8051	Open Areas (8/19/04)
Rule 8061	Paved and Unpaved Roads (8/19/04)
Rule 8071	Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081	Agricultural Sources (9/16/04)

California Environmental Quality Act (CEQA)

California Code of Regulations (CCR), Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)

California Health & Safety Code (CH&S), Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic "Hot Spots"), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

III. PROJECT LOCATION:

The proposed equipment will be located within NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 (See Attachment B). The closest population center is the residential district of Avenal approximately 6 miles to the southwest. The City of Huron is located approximately 8 miles to the north, and the City of Coalinga is located approximately 16 miles to the west.

The site is located northeast of the city of Avenal, in Kings County. The proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

Combined-Cycle Combustion Turbine Generators
Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0048 lb/MMBtu (without duct burner firing)
0.0050 lb/MMBtu (with duct burner firing)

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)
The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the

HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump
Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

V. EQUIPMENT LISTING:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

Each CTG will be equipped with a Dry Low NO_X combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low NO_X combustors and a SCR system with ammonia injection can achieve a NO_X emission rate of 2.0 ppmvd @ 15% O_2. CO emissions of 2.0 ppmvd @ 15% O_2 have been demonstrated with the use of an oxidation catalyst [(1)]. And the use of DLN combustors and good combustion practices can achieve VOC emissions of 2.0 ppmvd @ 15% O_2.

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_X formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

ii. C-3953-12-1 (Boiler)

Emissions from natural gas-fired boilers include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when burning natural gas. NO_X formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_X). Due to the low fuel nitrogen content of natural gas, nearly all NO_X emissions are thermal NO_X. Formation of thermal NO_X is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The Cleaver Brooks boiler will control the formation of thermal NO_X with an Cleaver Brooks ultra low NO_X burner. Cleaver Brooks burners reduce NO_X by pre-mixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes Prompt NO_X. This also eliminates the traditional NO_X versus CO tradeoff.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The diesel-fired emergency IC engine (fire pump) will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on very low (0.0015%) sulfur diesel.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[2]

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces SO_X emissions by approximately 99% from standard diesel fuel.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The natural gas-fired emergency IC engine (generator) will be equipped with an intercooler/aftercooler, lean burn technology, and will be fired on PUC-Regulated natural gas.

The emission control devices/technologies and their effect on natural gas engine emissions are detailed below.

[2] From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

VII. GENERAL CALCULATIONS:

The facility has proposed to limit the annual facility wide NO_X emission to 198,840 lb/year, and the annual facility wide CO emission to 197,928 lb/year.

All PM_{10} emissions are assumed to be $PM_{2.5}$ emissions.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- Maximum daily emissions for each CTG for VOC, PM_{10} and SO_X during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.
- The commissioning period will not exceed 408 hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for NO_X, CO, and VOC are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for VOC are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was

operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule.

- The facility has proposed a facility wide NO_X emission limit of 198,840 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for NO_X are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated NO_X emissions from an individual turbine operating at this scenario (calculated in Section VII.C.2) is not greater than the proposed facility wide NO_X emission limit; however the NO_X emissions from the operation of both turbines according to this scenario are far greater than the proposed facility wide NO_X emission limit. Therefore, the facility wide limit is a valid limit and the NO_X emissions from the turbines will ultimately be restricted by this limit.

- The facility has proposed a facility wide CO emission limit of 197,928 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for CO are estimated assuming the CTG is operated according to a weekend shutdown and weekday hot start scenario. The weekend shutdown and weekday hot start scenario results in CTG operation of 624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated CO emissions from this scenario (calculated in Section VII.C.2) are greater than the proposed facility wide CO emission limit; therefore the facility wide emissions limit is a valid limit and the turbine's CO emissions will ultimately be restricted by this limit.

- Maximum annual emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming the CTG is operated according to a baseload scenario. The baseload scenario results in CTG operation of 800 hours operating while firing at full load with the duct burner and 7,960 hours operating while firing at full load without the duct burner.

ii. C-3953-12-1 (Boiler)

- External O_2 stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.4 MMBtu/hr.
- Maximum SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

  (1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 lb/MMBtu

- Maximum daily and annual emissions for all pollutants are estimated assuming twelve (12) hours per day and 1,248 hours per year operating at full load.[3]
- Operating schedule of 12 hr/day and 1,248 hrs/year.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

- Diesel F factor (adjusted to 60 °F) is 9,051 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher heating value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

iv. C-3953–14-1 (Natural gas IC engine powering electrical generator)

- EPA F-factor (adjusted to 60 °F) is 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Fuel heating value 1,013 Btu/dscf (per applicant)
- Maximum daily SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

  (1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 lb/MMBtu

- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

[3] Applicant has indicated that the unit will be used a maximum of 12 hours on a startup day.

B. Emission Factors

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A(5)	N/A(4)

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment D for applicant proposed emissions) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

Maximum Emission Rate Without Duct Burner Firing:

The worst-case NO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 32 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 13.55 lb-NO_X/hr

CO Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= 8.35 lb-CO/hr

VOC Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0018 lb-VOC/MMBtu)
= 3.34 lb-VOC/hr

PM_{10} Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0048 lb-PM_{10}/MMBtu)
= 8.91 lb-PM_{10}/hr

[4] PM_{10} and SO_X emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= 5.23 lb-SO_X/hr

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w/o duct burner 1.832 MMscf/hour, as calculated below)
(1,856.3 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 1.832 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 1.832 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 25.31 lb-NH3/hr

Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 32 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	13.55	8.35	3.34	8.91	5.23	25.31
ppmvd @ 15% O_2 limits	2.0	2.0	1.4	--	--	10.0
lb/MMBtu*	0.0073	0.0045	0.0018	0.0048	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

<u>Maximum Emission Rate With Duct Burner Firing:</u>

The worst-case NO_X, SO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 101 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 17.20 lb-NO_X/hr

CO Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **10.60 lb-CO/hr**

VOC Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0025 lb-VOC/MMBtu)
= **5.89 lb-VOC/hr**

PM_{10} Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0050 lb-PM_{10}/MMBtu)
= **11.78 lb-PM_{10}/hr**

SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= **6.65 lb-SO_X/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w duct burner 2.326 MMscf/hour, as calculated below)
(2,356.5 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 2.326 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 2.326 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 32.13 lb-NH3/hr

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	17.20	10.60	5.89	11.78	6.65	32.13
ppmvd @ 15% O_2 limits	2.0	2.0	2.0	--	--	10.0
lb/MMBtu*	0.0074	0.0045	0.0025	0.0050	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Startup and Shutdown Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Maximum Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A(6)	N/A(5)
Average Mass Emission Rate (per turbine, lb/hr)	80	900	16	N/A(6)	N/A(6)

ii. C-3953-12-1 (Boiler)

For the new boiler, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant. The SO_X emission factor is calculated as shown below.

Boiler Emission Factors*		
Pollutant	ppmv @ 3%O_2	lb/MMBtu
NO_X	9.0	0.011
CO	50.0	0.037
VOC	10.0	0.0043
PM_{10}	--	0.005
SO_X**	--	0.00282

*Note: lb/MMBtu equivalent of ppmv values @ 3% O_2 as provided by the Applicant
** SO_X emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

(1 ~~gr-S~~/100 ~~dscf~~ x 1 ~~lb-S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb-S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

Diesel-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	3.4	Engine Manufacturer
CO	0.447	Engine Manufacturer
VOC	0.38	Engine Manufacturer
PM_{10}	0.059	Engine Manufacturer
*SO_X	0.005	Mass Balance Equation Below

[5] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

$$^{*}0.0015\% \times \frac{7.1\,lb \cdot fuel}{gallon} \times \frac{2\,lb \cdot SO_2}{1\,lb \cdot S} \times \frac{1\,gal}{137{,}000\,Btu} \times \frac{1\,hp\ input}{0.35\,hp\ out} \times \frac{2{,}542.5\,Btu}{hp \cdot hr} \times \frac{453.6\,g}{lb} = 0.005\,\frac{g\,SOx}{hp \cdot hr}$$

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

For the new emergency natural gas-fired IC engine powering an electrical generator, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the fuel sulfur content from District Policy APR 1720.

Natural Gas-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	1.0	Engine Manufacturer
CO	0.6	Engine Manufacturer
VOC	0.33	Engine Manufacturer
PM_{10}	0.034	Engine Manufacturer
**SO_X	0.0094	Mass Balance Equation Below

**SO_X is calculated as follows:

$$0.00285\ \frac{lb - SO_x}{MMBtu} \times \frac{1\,MMBtu}{1{,}000{,}000\,Btu} \times \frac{2{,}542.5\,Btu}{bhp - hr} \times \frac{1\,bhp\ input}{0.35\,bhp\ out} \times \frac{453.6\,g}{lb} = 0.0094\ \frac{g - SO_x}{bhp - hr}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this is a brand new facility, the pre-project potential to emit (PE1) for all the emissions units associated with this project is equal to zero.

2. Post Project Potential to Emit (PE2):

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A[(6)]	11.78	8.91	8.91	23.56
SO_X	N/A[(7)]	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A[(7)]	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A[(7)]	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

[6] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

c. *Maximum Annual PE*

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 ~~gr S~~/100 ~~dscf~~) x (1 ~~lb S~~/7000 ~~gr~~) x (64 lb SO_X/32 ~~lb S~~) x (1 ~~scf~~/1013 ~~Btu~~) x (10^6 ~~Btu~~/MMBtu)
= 0.001 lb-SO_X/MMBtu

<u>CTG w/o Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 1.86 lb-SO_X/hr

<u>CTG w/ Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 2.36 lb-SO_X/hr

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

<u>Scenario 1) Weekend and Weekday Hot Start:</u>

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

<u>Scenario 2) Weekend Shutdown and Weekday Hot Start:</u>

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

d. *Maximum Quarterly PE*

Maximum quarterly emissions for each unit will be determined by dividing the maximum annual emissions into 4 quarters:

Maximum Quarterly Potential to Emit						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
1st Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
2nd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
3rd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
4th Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993

ii. C-3953-12-1 (Boiler)

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{NOx} = (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.41 lb NO_X/hr**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **4.9 lb NO_X/day**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **513 lb NO_X/year**

= (513 lb NO_X/year) ÷ (4 qtr/year)
= **128 lb NO_X/qtr**

PE_{CO} = (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **1.38 lb CO/hr**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **16.6 lb CO/day**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **1,727 lb CO/year**

= (1,727 lb CO/year) ∗ (4 qtr/year)
= **432 lb CO/qtr**

PE_{VOC} = (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.16 lb VOC/hr**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.9 lb VOC/day**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **201 lb VOC/year**

= (201 lb/year) ∗ (4 qtr/year)
= **50 lb VOC/qtr**

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

PE_{SOx} = (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.11 lb SO_X/hr**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.3 lb SO_X/day**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **132 lb SO_X/year**

= (132 lb/year) ∗ (4 qtr/year)
= **33 lb SO_X/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-1)

	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	0.41	4.9	128	513
CO	1.38	16.6	432	1,727
VOC	0.16	1.9	50	201
PM_{10}	0.19	2.2	58	233
SO_X	0.11	1.3	33	132

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **2.16 lb NO_X/hr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **51.8 lb NO_X/day**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **27 lb NO_X/qtr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **108 lb NO_X/year**

PE_{CO} = (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.28 lb CO/hr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb ∗ (24 hr/day)
= **6.8 lb CO/day**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **4 lb CO/qtr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **14 lb CO/year**

PE_{VOC} = (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.24 lb VOC/hr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **5.8 lb VOC/day**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **3 lb VOC/qtr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **12 lb VOC/year**

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

PE_{SOx} = (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.00 lb SO_X/hr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.1 lb SO_X/day**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **0 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-13-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	2.16	51.8	27	108
CO	0.28	6.8	4	14
VOC	0.24	5.8	3	12
PM_{10}	0.04	0.9	0.5	2
SO_X	0.00	0.1	0	0

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.90 lb NO_X/hr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **45.5 lb NO_X/day**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **24 lb NO_X/qtr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **95 lb NO_X/year**

PE_{CO} = (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.14 lb CO/hr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **27.3 lb CO/day**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **14 lb CO/qtr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **57 lb CO/year**

PE_{VOC} = (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.63 lb VOC/hr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **15.0 lb VOC/day**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **8 lb VOC/qtr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **31 lb VOC/year**

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

PE_{SOx} = (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.02 lb SO_X/hr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.4 lb SO_X/day**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-14-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	1.90	45.5	24	95
CO	1.14	27.3	14	57
VOC	0.63	15.0	8	31
PM_{10}	0.06	1.5	1	3
SO_X	0.02	0.4	0	1

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The District is issuing a DOC for this project and not individual ATC's. Therefore, the SSPE2 will be determined by summing the potential emissions from the units included in the DOC.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3	$PM_{2.5}$ ***
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972	80,656
C-3953-11-1			34,489	80,656	16,694	219,972	80,656
C-3953-12-1			201	233	132	0	233
C-3953-13-1			12	2	0	0	2
C-3953-14-1			31	3	1	0	3
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**	**161,550**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.
*** All PM_{10} emissions are $PM_{2.5}$.

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

Major Source Determination						
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)	$PM_{2.5}$ (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521	161,550
Major Source Threshold	50,000	200,000	50,000	140,000	140,000	200,000
Major Source?	Yes	No	Yes	Yes	No	No

6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for NO_X, VOC, and PM_{10} emissions after this project. However, since the units in this project are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline NO_X, CO, VOC, PM_{10} and SO_X emissions will be set equal to the following:

BE = 0 lb/year

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

Since this is a new facility, this project cannot be considered a Major Modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The two CTGs will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

ii. C-3953-12-1 (Boiler)

The boiler will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

- {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]

- Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

ii. C-3953-12-1 (Boiler)

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

<u>Proposed Rule 1081 Conditions</u>:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of a DOC application, Avenal Power Center, LLC is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. BACT:

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

ii. C-3953-12-1 (Boiler)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new boiler with a PE greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, and PM_{10} criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired IC engine (fire pump) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired IC engine (generator) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine = or > 50 MW, Uniform Load, with Heat Recovery].

ii. C-3953-12-1 (Boiler)

BACT Guideline 1.1.2 is applicable to the 37.4 MMBtu/hr boiler. [Boiler - > 20 MMBtu/hr, Natural gas-fired, base-loaded or with small load swings.]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT Guideline 3.1.8, applies to the natural gas-fired emergency IC engine powering an electrical generator. [Emergency Gas-Fired I.C. Engine > or = 250 hp, Lean Burn]

3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units C-3953-10-1 and -11-1 see Attachment F.

For Permit Unit C-3953-12-1 see Attachment F.

For Permit Unit C-3953-13-1 see Attachment F.

For Permit Unit C-3953-14-1 see Attachment F.

4. BACT Summary:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT has been satisfied by the following:

NO_X: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with Dry Low NO_X Combustors, SCR with ammonia injection and natural gas fuel.

VOC: 1.5 ppmv @ 15% O_2 (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% O_2 (with duct burner firing; 3-hr rolling average).

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: PUC regulated natural gas with a sulfur content of 1.0 gr/100 scf or less

ii. C-3953-12-1 (Boiler)

BACT has been satisfied by the following:

NO_X: 9.0 ppmv @ 15% O_2 with Ultra Low NO_X burners and natural gas fuel.

VOC: Natural gas fuel.

PM_{10}: Natural gas fuel.

SO_X: Natural gas fuel.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT has been satisfied by the following:

NO_X: Certified NO_X emissions of 6.9 g/hp·hr or less

VOC: No VOC control. Any add on VOC control device would void the Underwriters Laboratory (UL) certification.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT has been satisfied by the following:

NO_X: = or < 1.0 g/bhp-hr (lean burn natural gas fired engine, or equal)

VOC: 90% control efficiency (oxidation catalyst, or equal)

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X, CO, VOC, PM_{10}, and SO_X emissions. Therefore, offset calculations are necessary.

Offset Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	No	Yes	Yes	No

2. Quantity of Offsets Required:

Per District Rule 2201, Section 4.6.1, emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X, VOC, and PM_{10} is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Facility Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit units C-3953-13-1 and C-3953-14-1 will be exempt from providing offsets and the emissions associated with these permit units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = ([SSPE2 – Emergency Equipment - Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

<u>NO_X Offset Calculations:</u>

The facility has proposed to provide the same quarterly offsets that were required to be provided in the facility's initial project (C-1080386). The reason for this request is to enable the facility to preserve full flexibility to operate the facility at the previously permitted rates during any calendar quarter, provided the new annual emission limits are not exceeded. The facility is required to maintain a 12 month rolling calculation of their NO_X and CO emissions; therefore compliance with this quarterly limit will be enforceable. The quarterly offsets from project C-1080386 are shown below.

Quarterly Emissions to be Offset (Project C-1080386)

Annual Offsets = 268,415 lb/year * DOR

Quarterly Offsets $_{1st\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{2nd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{3rd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{4th\ Qtr}$ = 67,103.75 lbs of NO_X * DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of NO_X ERC's that need to be withdrawn is:

Offsets Required = 268,415 lb-NO_X/year x 1.5
Offsets Required = 402,623 lb-NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
NO_X	100,655	100,656	100,656	100,656	402,623

The applicant has stated that the facility plans to use ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 to offset the increases in NO_X emissions associated with this project. The above Certificates have available quarterly NO_X credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-899-2	2,243	2,243	2,243	2,243	**8,972**
ERC #C-902-2	13,879	6,131	1,086	8,539	**29,635**
ERC #N-720-2	0	9	1,255	437	**1,701**
ERC #N-722-2	0	1,166	88,317	1,422	**90,905**
ERC #N-726-2	0	0	4,728	0	**4,728**
ERC #N-728-2	10,542	3,731	2,487	5,171	**21,931**
ERC #S-2814-2	6,121	13,869	18,914	11,461	**50,365**
ERC #S-2321-2*	51,000	51,000	51,000	51,000	**204,000**
Total	**83,784**	**78,147**	**170,027**	**80,269**	**412,227**

*ERC certificate split from this ERC.

Project NO_X offset requirements

The applicant states that NO_X ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 will be utilized to supply the NO_X offset requirements.

Per Rule 2201 Section 4.13.8, Actual Emission Reductions (i.e. ERCs) that occurred from April through November (i.e. 2nd and 3rd Quarter), inclusive, may be used to offset increases in NO_X or VOC during any period of the year. Since 3rd quarter NO_X ERCs will be used to offset NO_X emissions, the above applies to the NO_X ERCs.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NO_X Emissions to be offset: (at a 1.5:1 DOR):	100,655	100,656	100,656	100,656
Available ERCs from certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2*:	83,784	78,147	170,027	80,269
3rd qtr. ERCs applied to 1st qtr. ERCs:	16,871	0	-16,871	0
3rd qtr. ERCs applied to 2nd qtr. ERCs:	0	22,509	-22,509	0
3rd qtr. ERCs applied to 4th qtr. ERCs:	0	0	-20,387	20,387
Remaining ERCs from certificates S-2321-2:	0	0	9,604	0
Remaining NO_X emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

VOC Offset Calculations:

VOC SSPE2	= 69,222 lb/year
C-3953-13-1 (VOC)	= 12 lb/year
C-3953-14-1 (VOC)	= 31 lb/year
VOC offset threshold	= 20,000 lb/year

Offsets = [69,222 – (12) – (31) – 20,000]
= 49,179 lb/year ∗ DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = (49,179 lb/year ÷ 4 qtr/year) ∗ DOR
= 12,294.75 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of VOC ERC's that need to be withdrawn is:

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
VOC	18,442	18,442	18,442	18,442	73,769

The applicant has stated that the facility plans to use ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 to offset the increases in VOC emissions associated with this project. The above Certificates have available quarterly VOC credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-897-1	45	45	45	45	**180**
ERC #C-898-1	5,480	6,496	4,696	6,616	**23,288**
ERC #N-724-1	0	0	241	0	**241**
ERC #N-725-1	0	0	709	0	**709**
ERC #S-2812-1	31,432	31,424	31,417	31,417	**125,690**
ERC #S-2813-1	12,500	12,500	12,500	12,500	**50,000**
ERC #S-2817-1	11,431	11,424	11,417	11,417	**45,689**
Total	**60,887**	**61,887**	**61,022**	**61,991**	**245,787**

Project VOC offset requirements

The applicant states that NO_X ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 will be utilized to supply the VOC offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
VOC Emissions to be offset: (at a 1.5:1 DOR):	18,442	18,442	18,442	18,442
Available ERCs from certificates C-897-1, C-898-1, N-724-1, N-725-1,	5,525	6,541	5,691	6,661
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
VOC Emissions to be offset: (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
Available ERCs from certificates S-2812-1, S-2813-1, and S-2817-1	55,363	55,348	55,334	55,334
Remaining ERCs from certificates S-2812-1, S-2813-1, and S-2817-1:	42,446	43,447	42,583	43,553
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 161,550 lb/year
C-3953-13-1 (PM_{10}) = 2 lb/year
C-3953-14-1 (PM_{10}) = 3 lb/year
PM_{10} Offset threshold = 29,200 lb/year

Offsets = [(161,550 – (2) – (3) - 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Offsets = (132,345 lb/year ÷ 4 qtr/year) ∗ DOR
= 33,086 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{2nd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{3rd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{4th\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	49,630	49,629	49,629	49,630	198,518

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-896-4	80	80	80	80	**320**
ERC #N-721-4	0	0	3,215	0	**3,215**
ERC #N-723-4	0	0	985	0	**985**
ERC #S-2791-5	92,179	23,666	69,157	96,288	**281,290**
ERC #S-2790-5	12,862	491	0	8,499	**21,852**
ERC #S-2789-5	6	14	12	8	**40**
ERC #S-2788-5	5	7	3	6	**21**
ERC #N-762-5	21,000	21,000	21,000	21,000	**84,000**
Total	**126,131**	**45,256**	**94,449**	**125,877**	**391,723**

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Attachment H). Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

<u>Offset Conditions:</u>

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

- ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

D. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII.C.6 above, the SSPE2 is greater than the Major Source threshold for NO_X, VOC, and PM_{10}. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

Post-Project Potential to Emit						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-3953-10-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-11-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-12-1	4.9	16.6	1.9	2.2	1.3	0
C-3953-13-1	51.8	6.8	5.8	0.9	0.1	0
C-3953-14-1	45.5	27.3	15.0	1.5	0.4	0
Threshold (lb/day)	**100**	**100**	**100**	**100**	**100**	**100**
Notification Required?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

According to the table above, permit units C-3953-10-1 and -11-1 will each have a Potential to Emit greater than 100 lb/day for NO_X, CO, VOC, PM_{10}, SO_X, or NH_3 emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

e. Offset Threshold

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	198,840	20,000 lb/year	Yes
CO	0	197,928	200,000 lb/year	No
VOC	0	69,222	20,000 lb/year	Yes
PM_{10}	0	161,550	29,200 lb/year	Yes
SO_X	0	33,521	54,750 lb/year	No

As detailed above, offset thresholds were surpassed for NO_X, VOC, and PM_{10} emissions with this project; therefore public noticing is required for offset purposes.

f. SSIPE Notification

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary

Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

SSIPE Notification					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_X	198,840	0	198,840	20,000 lb/year	Yes
CO	197,928	0	197,928	20,000 lb/year	Yes
VOC	69,222	0	69,222	20,000 lb/year	Yes
PM_{10}	161,550	0	161,550	20,000 lb/year	Yes
SO_X	33,521	0	33,521	20,000 lb/year	Yes

As demonstrated above, the SSIPE's for NO_X, CO, VOC, PM_{10} and SO_X emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity.

Proposed Rule 2201 (DEL) Conditions:

The following condition will be included to demonstrate compliance with facility wide annual NO_X and CO emissions limits.

- Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

i. C-3953-10-1 and C-3953-11-1 (Turbines)

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 will consist of lb/day and/or emission factors.

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

ii. C-3953-12-1 (Boiler)

The DELs for the boiler will consist of lb/MMBtu and ppmv emissions limits. This will be sufficient to establish a maximum daily potential to emit based on the maximum daily fuel use limit.

- Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00282 lb/MMBtu. [District Rules 2201, 4305, 4306, and 4351]

In addition the following permit conditions will appear on the permit:

- {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

For the emergency IC engine powering a generator, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

F. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this facility is a new major source; therefore this requirement is applicable. Included in Attachment I is Avenal Power Center's certification for the Avenal Energy Project.

G. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO_x	Pass	N/A	N/A	N/A	Pass
SO_x	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.38	1.6	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

H. Compliance Assurance:

1. Source Testing

i. C-3953-10-1 and C-3953-11-1

District Rule 4703 requires NO_X and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, CO, VOC, PM_{10}, and ammonia slip will be required within 60 days after the end of the commissioning period and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

40 CFR Part 60 subpart Db requires NO_X testing for the duct burners. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to NO_X testing required by 40 CFR 60 subpart Db.

ii. C-3953-12-1

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*. Source testing requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

Pursuant to District Policy APR 1705, source testing is not required for emergency standby IC engines to demonstrate compliance with Rule 2201.

2. Monitoring

i. C-3953-10-1 and C-3953-11-1

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Avenal Power Center, LLC will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

i. C-3953-10-1 and C-3953-11-1

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

The following permit condition will be listed on permit as follows:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

iii. C-3953-13-1 and C-3953-14-1

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, these IC engines are subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

4. Reporting

i. C-3953-10-1 and C-3953-11-1

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

ii. C-3953-12-1

No reporting is required to demonstrate compliance with Rule 2201.

iii. C-3953-13-1 and C-3953-14-1

No reporting is required to demonstrate compliance with Rule 2201.

Rule 2520 Federally Mandated Operating Permits

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for NO_X, VOC, and PM_{10} after this project.

- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.

- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.

- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is not required to obtain a PSD permit.

Pursuant to Rule 2520 section 5.3.1 Avenal Power Center must submit a Title V application within 12 months of commencing operations. No action is required at this time.

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in November of 2011.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

The following condition will be placed on permits C-3953-10-1, -11-1 and -14-1 to ensure that Avenal Power Center, LLC submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.[8] AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low NO_X combustor-equipped large frame turbine.

[7] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).
[8] Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

Hazardous Air Pollutant Emissions (per CATEF)
Avenal Energy Project – GE Frame 7 (with Duct Burners)

Hazardous Air Pollutant	CATEF Emission Factor (lb/MMSCF)(1)	Maximum Hourly Emissions per Turbine (lb/hr) (2)	Maximum Annual Emissions per Turbine (tpy) (3)	Maximum Annual Emissions both Turbines (tpy)
Acetaldehyde	4.08E-02	0.09	0.33	0.67
Acrolein	3.69E-03	0.01	0.03	6.04E-02
Benzene	3.33E-03	0.01	0.03	5.45E-02
1,3-Butadiene	4.39E-04	9.38E-04	3.59E-03	7.19E-03
Ethyl benzene	3.26E-02	0.07	0.27	0.53
Formaldehyde	1.65E-01	0.35	1.35	2.70
Hexane	2.59E-01	0.55	2.12	4.24
Naphthalene	1.33E-03	2.84E-03	1.09E-02	2.18E-02
Polycyclic aromatic hydrocarbons (PAH)	---	---	---	---
Anthracene	3.38E-05	7.22E-05	2.77E-04	5.53E-04
Benzo(a)anthracene	2.26E-05	4.83E-05	1.85E-04	3.70E-04
Benzo(a)pyrene	1.39E-05	2.97E-05	1.14E-04	2.28E-04
Benzo(b)fluoranthrene	1.13E-05	2.41E-05	9.25E-05	1.85E-04
Benzo(k)fluoranthrene	1.10E-05	2.35E-05	9.00E-05	1.80E-04
Chrysene	2.52E-05	5.38E-05	2.06E-04	4.12E-04
Dibenz(a,h)anthracene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Indeno(1,2,3-cc)pyrene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Propylene oxide	2.96E-02	6.32E-02	2.42E-01	0.48
Toluene	1.33E-01	0.28	1.09	2.18
Xylenes	6.53E-02	0.14	0.53	1.07
Total			**6.01**	**12.02**

(1) From AP-42 and CATEF databases and source tests.
(2) Based on a maximum hourly turbine fuel use of 2,224.1 MMBtu/hr (with duct burner) and fuel HHV of 1,021 Btu/scf. (2.14 MMscf/hr)
(3) Based on a maximum annual turbine fuel use of 16,711,728 MMBtu/year (with duct burner) and fuel HHV of 1,021 Btu/scf. (16,368 MMscf/yr)

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the Avenal Power Center, LLC Project will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

40 CFR 60 – Subpart Dc

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_X and PM_{10}.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixtured of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boiler in this project is not subject to the particulae matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.47c – Emission Monitoring for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §40.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO_2 emissions.

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

- Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that records be kept for five years.

40 CFR 60 – Subpart GG

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 - Subpart IIII

§60.4200 - Applicability

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.
2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so further discussion is required.

40 CFR Part 60, Subpart JJJJ

The engine in this project is rated at over 100 bhp and per 60.4233(e) is subject to the limits presented in Table 1 of this subpart. The Table 1 limits as well as the proposed emissions are shown on the following table. This regulation does not specify an emissions averaging period.

	Table 1 Limit	Proposed Emissions	Compliant
NOx (g/bhp-hr)	2.0	1.0	Yes
CO (g/bhp-hr)	4.0	0.6	Yes
VOC (g/bhp-hr)	1.0	0.33	Yes

Therefore, the natural gas-fired IC engine in this project meets all applicable requirements of this subpart.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 1,794.5 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

Avenal Power Center is proposing a NO_X emission concentration limit of 2.0 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.44 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 6.13 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.72 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.28 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.23 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.97 lb/hr; or SOx (as SO2) – 5.11 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

<u>Section 60.4330 - Standards for Sulfur Dioxide:</u>

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Avenal Power Center is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

<u>Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:</u>

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Avenal Power Center does not use water or steam injection in their turbines therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

Avenal Power Center has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Avenal Power Center will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, Avenal Power Center is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Section 60.4350 – CEMS Data and Excess NO_X Emissions:

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Avenal Power Center is proposing to monitor the NO_X emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

Section 60.4355 – Parameter Monitoring Plan:

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, Avenal Power Center is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Avenal Power Center is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Avenal Power Center has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Avenal Power Center is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Avenal Power Center is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for the turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Avenal Power Center is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. Avenal Power Center is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Avenal Power Center will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Avenal Power Center is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

Avenal Power Center will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Avenal Power Center has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, Avenal Power Center is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Avenal Power Center is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. Avenal Power Center is not proposing to measure the SO_2 in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

40 CFR 63 Subpart ZZZZ

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§6585(b) states, "A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site."

§6585(c) states, "An area source of HAP emissions is a source that is not a major source."

The facility is not a major source as defined in §6585(b). Therefore, this facility is an area source of HAP emissions.

§6590(a) states, "An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand." Since the engines in this project are new stationary RICE's at an area source of HAP emissions, they are defined as affected sources.

§6590(a)(2) defines the criteria for an new stationary RICE as follows:

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

This facility is an area source of HAP emissions. The engines at this facility have not been constructed and therefore meets the definition of an new stationary RICE as defined in §6590(a)(2)(iii).

§6590(b)(1) states that an affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

Since the enignes in this project are not located at a major source of HAP emissions they do not qualify for the limited requirements stated above.

§6590(b)(2) and (3) apply to landfill or digester gas fired RICE's and existing RICE's. Since the engines in ths project are not exsiting RICE's and are fired on diesel fuel or natural gas, these sections do not apply to the RICE's in this project.

§6590(c) states that an affected source that is listed below must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

- new or reconstructed stationary RICE located at an area source,
- new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP,
- or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP,

Since both the RICE's in this project are new stationary RICE's located at an area source, they will demonstrate compliance with this Subpart by demonstrating compliance with the requirements of 40 CFR part 60 subpart IIII and for compression ignition engines and 40 CFR part 60 subpart JJJJ for spark ignited engines. As shown previously in this evaluation, the RICE's in this project meet the requirements of 40 CFR part 60 subpart IIII and subpart JJJJ; therefore they meet the requirements of this subpart.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

ii. C-3953-12-1 (Boiler)

Based on past experiences with natural gas-fired boilers, no visible emissions are expected to be as dark as or darker than Ringelmann 1 (or 20% opacity). The following condition will be placed on the DOC to assure compliance with this rule.

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, the following condition will be added to the permit to assure compliance with this rule.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

Screen HRA Summary				
	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-3953-10-1 (Turbine #1)	0.0	0.0	0.02	No
C-3953-11-1 (Turbine #2)	0.0	0.0	0.02	No
C-3953-12-1 (Auxiliary Boiler)	0.0	0.0	0.01	No
C-3953-13-1 (Diesel-Fired IC Engine Fire Pump)	N/A*	N/A*	0.01	No
C-3953-14-1 (NG-Fired IC Engine Generator)	0.2	0.0	0.0	No

* Acute and Chronic Hazard Indices were not calculated since there is not a risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

i. C-3953-10-1 and –11-1 (Turbines)

PM Conc. (gr/scf) = (PM emission rate) x (7000 gr/lb)

PM_{10} emission rate = 11.78 lb/hr. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 1,071,653 dscfm

PM Conc. (gr/scf)=[(11.78 lb/hr) ∗ (7,000 gr/lb)] ÷ [(1,071,653 ft^3/min) ∗ (60 min/hr)]
PM Conc. = 0.0012 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

ii. C-3953-12-1 (Boiler)

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

F-Factor for NG:	8,578 dscf/MMBtu at 60 °F
PM10 Emission Factor:	0.005 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust:	100%
Exhaust Oxygen (O_2) Concentration:	3%

$$\text{Excess Air Correction to F Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

$$GL = \left(\frac{0.005\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0035\ grain/dscf < 0.1\ grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected and a permit condition will be listed on the permit as follows:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.059\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.014\ \frac{grain-PM}{dscf}$$

Since 0.014 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.034 \; \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = \; 0.008 \; \frac{grain-PM}{dscf}$$

Since 0.008 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the permit units in this project, and no further discussion is required.

Rule 4301 ***Fuel Burning Equipment***

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

ii. C-3953-12-1 (Boiler)

District Rule 4301 Limits			
Pollutant	NO_2	Total PM	SO_2
C-3953-12-1 (lb/hr)	0.41	0.19	0.10
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

iii. C-3953-13-1 (Diesel IC engine fire pump)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4304 Tuning Procedure for Boilers, Steam Generators and Process Heaters

This rule is only applicable to unit C-3953-12-1.

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to tune since it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the unit is not subject to this rule.

Rule 4305 Boilers Steam Generators and Process Heaters – Phase 2

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Conclusion

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

Section 5.1, NO_X and CO Emissions Limits

Section 5.1.1 requires that except for units subject to Sections 5.2, NO_X and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

With a maximum heat input of 37.4 MMBtu/hr, the applicable emission limit category is listed in Section 5.1.1, Table 1, Category B, from District Rule 4306.

Rule 4306 Emissions Limits				
Category	Operated on gaseous fuel		Operated on liquid fuel	
	NO_X Limit	CO Limit	NO_X Limit	CO Limit
B. Units with a rated heat input greater than 20.0 MMBtu/hr, except for categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	400 ppmv	40 ppmv or 0.052 lb/MMBtu	400 ppmv

For the unit:

- the proposed NO_x emission factor is 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O_2 (0.037 lb/MMBtu).

Therefore, compliance with Section 5.1 of District Rule 4306 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.2, Low Use

The unit annual heat input will exceed the 9 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.2, the requirements of this section do not apply to the unit.

Section 5.3, Startup and Shutdown Provisions

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.3.1 through 5.3.4.

According to boiler manufacturers, low NO_X burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the unit will be subject to the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 while in operation.

Section 5.4, Monitoring Provisions

Section 5.4.2 requires that permit units subject to District Rule 4306, Section 5.1 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_X, CO and O_2, or install and maintain APCO-approved alternate monitoring.

The facility has proposed to install a CEMS system to satisfy the requirements of this section. The following condition will assure compliance with this section.

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

Since the unit is not subject to the requirements listed in Section 5.2.1 or 5.2.2, it is not subject to Section 5.4.3 requirements.

Since the unit is not subject to the requirements of category H (maximum annual heat input between 9 billion and 30 billion Btu/year) listed in Section 5.1.1, it is not subject to Section 5.4.4 requirements.

Section 5.5, Compliance Determination

Section 5.5.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the permit as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Section 5.5.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permit as follows:

- {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Section 5.5.4 requires that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of District Rule 4306 the requirements of Section 5.5.4 do not apply.

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

A permit condition will be listed on the permit as follows:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

Section 6.1.2 requires that the operator of a unit subject to Section 5.2 shall record the amount of fuel use at least on a monthly basis. Since the unit is not subject to the requirements listed in Section 5.2, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.2.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The unit is not subject to Section 6.1.3. Therefore, the requirements of this section do not apply to the unit.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO_X	ppmv	EPA Method 7E or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be listed on the permit as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {2977} NO_X emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]
- {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]
- {2979} Stack gas oxygen (O_2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

The following permit conditions will be listed on the permit as follows:

- {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]
- {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4, Emission Control Plan (ECP)

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permit(s). Therefore, compliance with District Rule 4306 requirements is expected.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule is only applicable to unit C-3953-12.

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. If applicable, the emission limits, monitoring provisions, and testing requirements of this rule are satisfied when the unit is operated in compliance with Rule 4306. Therefore, compliance with this rule is expected.

Rule 4701 Internal Combustion Engines – Phase 1

This rule is only applicable to units C-3953-13-1 and –14-1.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 Internal Combustion Engines – Phase 2

This rule is only applicable to units C-3953-13-1 and –14-1.

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.2, except for the requirements of Sections 5.7 and 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following condition:

1) An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Section 3.15 defines an "Emergency Standby Engine" as an internal combustion engine which operates as a temporary replacement for primary mechanical or electrical power during an unscheduled outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the operator. An engine shall be considered to be an emergency standby engine if it is used only for the following purposes: (1) periodic maintenance, periodic readiness testing, or readiness testing during and after repair work; (2) unscheduled outages, or to supply power while maintenance is performed or repairs are made to the primary power supply; and (3) if it is limited to operate 100 hours or less per calendar year for non-emergency purposes. An engine shall not be considered to be an emergency standby engine if it is used: (1) to reduce the demand for electrical power when normal electrical power line service has not failed, or (2) to produce power for the utility electrical distribution system, or (3) in conjunction with a voluntary utility demand reduction program or interruptible power contract.

Therefore, unit C-3953-14-1, the emergency standby IC engine powering an electrical generator involved with this project will only have to meet the requirements of Sections 5.7 and 6.2.3 of this Rule.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, unit C-3953-13-1, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 5.7 of this Rule requires that the owner of an emergency standby engine shall comply with the requirements specified in Section 5.7.2 through Section 5.7.5 below:

1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.

2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.

3) Install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO and is allowed by Permit-to-Operate or Stationary Equipment Registration condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the following conditions will be listed on the DOC to ensure compliance:

C-3953-14-1 (Natural Gas IC engine electrical generator)

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

- An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on the DOC to ensure compliance:

C-3953-13-1 (Diesel IC engine fire pump)

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the DOC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

- {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

C-3953-14-1 (Natural Gas IC engine electrical generator)

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

This rule is only applicable to units C-3953-10-1 and -11-1.

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 180 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_X Emission Requirements:

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbines will meet the more stringent Tier 2 emission equirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average), therefore compliance with this section is expected. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines (General Electric Frame 7) must be less than 25 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Avenal Power Center is proposing a CO emission concentration limit of 2 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The DEL conditions shown in the Section 5.1.2 compliance section will ensure continued compliance with the requirements of this section.

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Avenal Power Center is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than six hours per day. Since this proposed duration is longer than what is allowed in Section 5.3.1.1, the facility must meet the requirements of Section 5.3.3.2. Section 5.3.3.2 states that at a minimum, a justification for the increased duration shall include the following:

A clear identification of the control technologies or strategies to be utilized; and

The facility has identified the following control technologies:

- Dry low-NOx combustors in the turbines;
- Oxidation catalyst in the HRSGs;
- SCR in the HRSGs;
- Good combustion practices;

- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures specified by the SCR vendor.

<u>A description of what physical conditions prevail during the period that prevent the controls from being effective; and</u>

The combined-cycle equipment startup duration depends on how fast the thick steel walls of the common steam turbine can be warmed to operating temperature without generating stress cracks. Steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. The allowable rate of temperature increase at the steam turbine is the limiting factor determining how quickly the gas turbines can achieve higher loads. This, in turn, limits how quickly the gas turbine combustors can achieve the lowest emitting operating mode, and this latter step is necessary for the units to be able to comply with the limits of Rule 4703.

<u>A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and</u>

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of four hours is required for the unit to come into compliance with the limits of Rule 4703. Depending on the temperature of the steam turbine at the time the start is initiated, shorter durations may be possible.

<u>A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and</u>

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

<u>A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and</u>

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the HRH and HP bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NOx to N_2. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufactúrer's recommended procedures.

<u>The basis for the requested additional duration.</u>

The startup curve in Attachment I and the description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, one hour is added to the above startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information asked for in Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines have not been installed. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Avenal Power Center will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. Avenal Power Center will be required, by permit condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Avenal Power Center will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Avenal Power Center will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The turbines operated by Avenal Power Center are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbines will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner both on and off. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

i. C-3953-10-1 and –11-1 (Turbines)

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_x exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_x: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_x produced per MMBtu of fuel.
- Weight of SO_x as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00282\ lb}{MMBtu} \times \frac{1\ (lb-mol)}{64\ lb} = 0.000045\ (lb-mol)$

- $R = \dfrac{0.7302\, ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \dfrac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

ii. C-3953-12-1 (Boiler)

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

Volume $SO_2 = \dfrac{n\ RT}{P}$

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\dfrac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$\frac{0.00282\, lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot °R} \times \frac{520°R}{14.7\, psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.97 \frac{parts}{million}$$

$$SulfurConcentration = 1.97 \frac{parts}{million} < 2{,}000 \text{ ppmv (or 0.2\%)}$$

Therefore, compliance with District Rule 4801 requirements is expected.

iii. C-3953-13-1 (Diesel IC engine powering a fire water pump)

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$\frac{0.000015\, lb - S}{lb - fuel} \times \frac{7.1 \text{ lb}}{\text{gal}} \times \frac{64 \text{ lb} - SO_2}{32 \text{ lb} - S} \times \frac{1 \text{ MMBtu}}{9{,}051 \text{ scf}} \times \frac{1 \text{ gal}}{0.137 \text{ MMBtu}} \times \frac{\text{lb} - \text{mol}}{64 \text{ lb} - SO_2} \times \frac{10.73 \text{ psi} - \text{ft}^3}{\text{lb} - \text{mol} - {}^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7 \text{ psi}} \times 1{,}000{,}000 = 1.0 \text{ ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine powering an electrical generator)

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$2.85 \quad \frac{lb - S}{MMscf - gas} \times \frac{1\, scf - gas}{1{,}000\, Btu} \times \frac{1\, MMBtu}{8{,}578\, scf} \times \frac{1\, lb - mol}{64\, lb - S} \times \frac{10.73\, psi - ft^3}{lb - mol - {}^\circ R} \times \frac{520^\circ R}{14.7\, psi} \times 1{,}000{,}000 = \quad 1.97 \quad \text{ppmv}$$

Since 1.97 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

District Rule 8011 General Requirements
District Rule 8021 Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities
District Rule 8031 Bulk Materials
District Rule 8041 Carryout And Trackout
District Rule 8051 Open Areas
District Rule 8061 Paved And Unpaved Roads
District Rule 8071 Unpaved Vehicle/Equipment Traffic Areas
District Rule 8081 Agricultural Sources

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

The requirements of this section are only applicable to C-3953-13-1.

Particulate Matter and VOC + NO_X, and CO Exhaust Emissions Standards:

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.20 g/kW-hr) for 2003 - 2005 model year engines with maximum power ratings of 174.3 - 301.6 bhp (equivalent to 130 - 225 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + NO_X, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) until three years after the date the Tier 3 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 3 emission standards, until three years after the date the Tier 4 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 4 emission standards; and not operate more than the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition, which is incorporated herein by reference. In addition, this subsection does not limit engine operation for emergency use and for emission testing to show compliance with (e)(2)(A)4. For this project the proposed emergency diesel IC engine will be used to power a firewater pump and is therefore allowed to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines three years after the applicable dates specified. This additional three-year allowance is reflected in the following table.

The engine involved with this project is a certified 2007 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 288 bhp Cummins Model #CFP83-F40 diesel-fired emergency IC engine as given by the manufacturer (for NO_X + VOC and PM emissions).

Requirements of Title 13 CCR, Section 2423							
Source	Maximum Rated Power	Model Year	NO_X	VOC	NO_X + VOC	CO	PM
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	1996-2002 (Tier 1)	6.9 g/bhp-hr (9.2 g/kW-hr)	1.0 g/bhp-hr (1.3 g/kW-hr)	--	8.5 g/bhp-hr (11.4 g/kW-hr)	0.40 g/bhp-hr (0.54 g/kW-hr)
Title 13 CCR, §2423	**174.3 – 301.6 bhp (130 - 225 kW)**	**2003-2005, extended to 2008 (Tier 2)**	--	--	**4.9 g/bhp-hr (6.6 g/kW-hr)**	**2.6 g/bhp-hr (3.5 g/kW-hr)**	**0.15 g/bhp-hr (0.20 g/kW-hr)**
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	2006 and later, extended to 2009 (Tier 3)	--	--	3.0 g/bhp-hr (4.0 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Cummins, Model #CFP83-F40	288 bhp	2007	--	--	3.8g/bhp-hr (5.1 g/kW-hr)	0.447 g/bhp-hr (0.60 g/kW-hr)	0.059 g/bhp-hr (0.079 g/kW-hr)
Meets Standard?			N/A	N/A	Yes	Yes	Yes

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data and/or CARB/EPA engine certification for this engine lists a NO_X emissions factor of 3.4 g/bhp-hr, a VOC emissions factor of 0.38 g/bhp-hr, a NO_X + VOC emission factor of 3.8 g/bhp-hr, a CO emission factor of 0.447 g/bhp-hr, and a PM_{10} emissions factor of 0.059 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

<u>Right of the District to Establish More Stringent Standards:</u>

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_X + VOC, VOC, NO_X, and CO emission rate standards; and

2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The requirements of this section are only applicable to C-3953-13-1.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-3953-10-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-11-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-12-1	3020-02-H	37.4 MMBtu/hr boiler	$953.00
C-3953-13-1	3020-10-C	288 bhp IC engine	$222.00
C-3953-14-1	3020-10-E	860 bhp IC engine	$557.00

ATTACHMENT A

FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3953-10-1:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in

accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated

emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from

the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance

with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

58. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

59. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

60. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

61. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

62. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

63. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

64. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

65. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

67. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-3953-11-1:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality

assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the

equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with

the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

EQUIPMENT DESCRIPTION, UNIT C-3953-12-1:
37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

5. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

6. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this DOC. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

7. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the DOC. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

10. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

11. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

12. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

13. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

14. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

15. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

16. Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]

17. {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

18. {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]

19. {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]

20. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

21. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

22. {2977} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]

23. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

24. {2979} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

25. {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

26. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

27. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

28. Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

29. {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

30. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

27\. {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

28. {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

29. {1835} The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

30. {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

31. {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

32. {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

33. {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

EQUIPMENT DESCRIPTION, UNIT C-3953-13-1:
288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

7. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

8. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

9. Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

10. Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

11. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

12. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

13. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

14. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

EQUIPMENT DESCRIPTION, UNIT C-3953-14-1:
860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

7. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

8. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

9. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

10. Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

11. {3405} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

12. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

13. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

14. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

16. {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

17. {3497} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

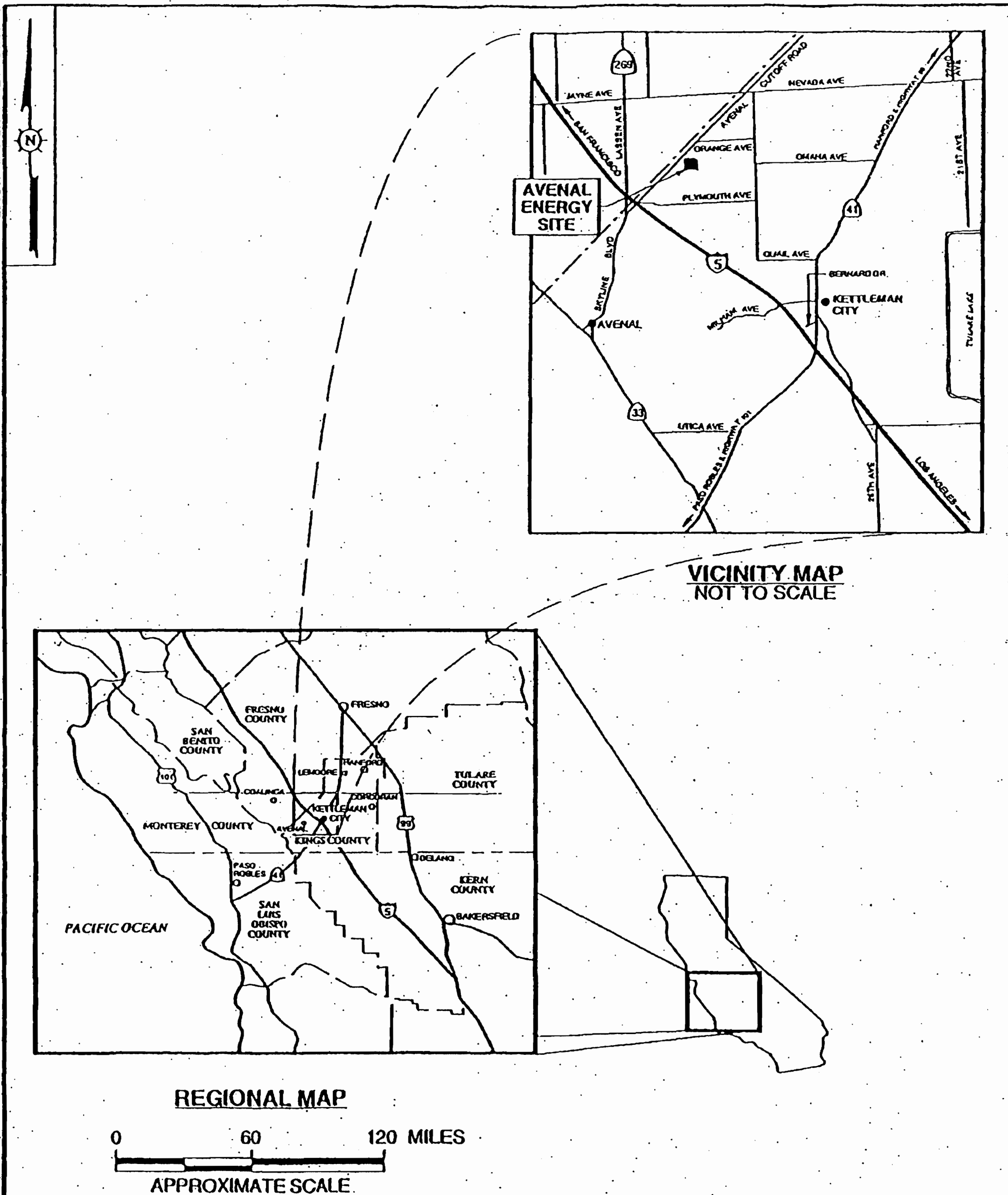
ATTACHMENT B

Project Location and Site Plan

ATTACHMENT C

CTG Commissioning Period Emissions Data

290317-AFC-2.0-1 REV1 09/05/08

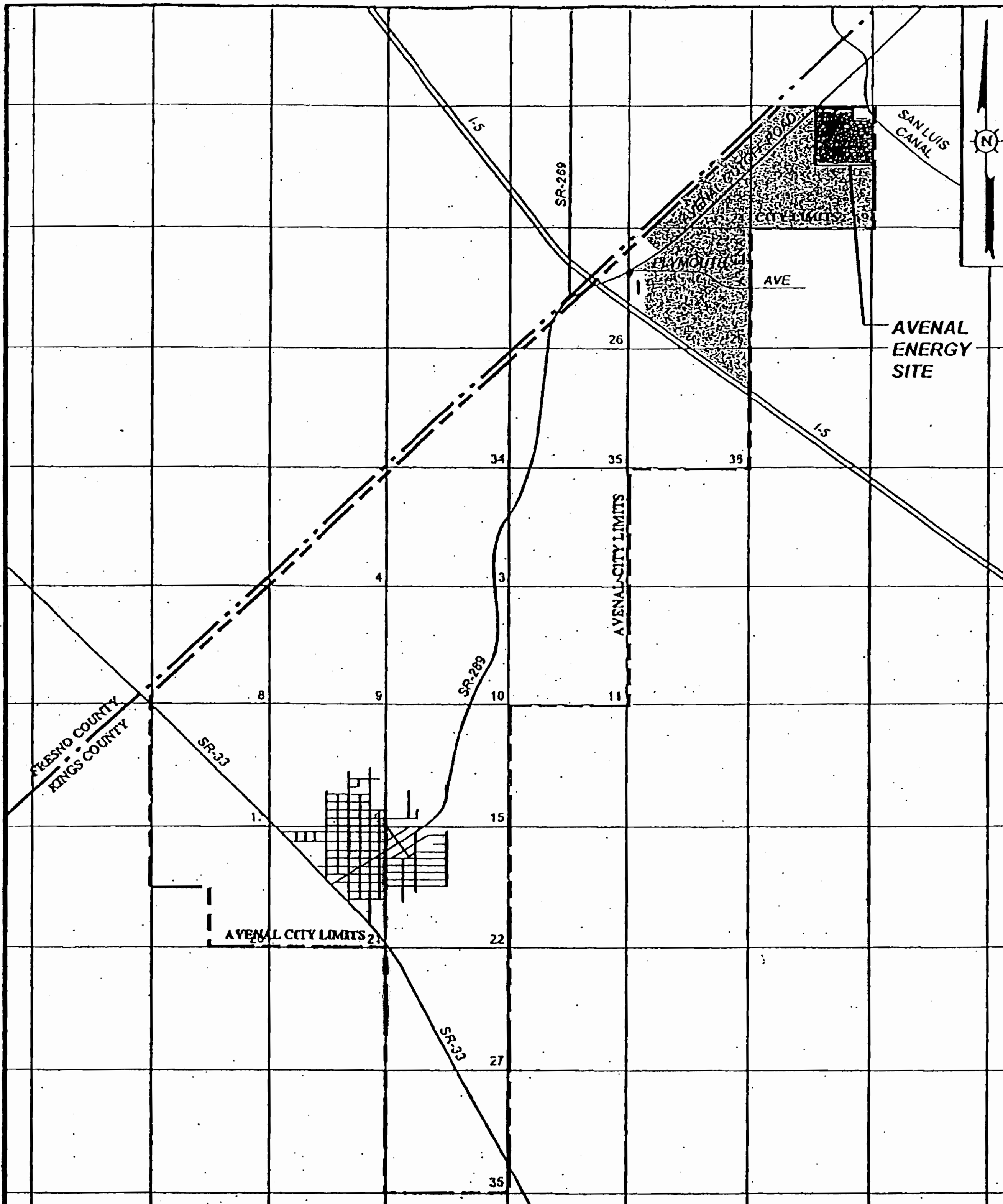


REGIONAL LOCATION MAP

FEDERAL ENERGY AVENAL, LLC

AVENAL ENERGY	FIGURE 2.0-1

280317-AFC-2.0-2 REV.09/13/01



LEGEND

INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)

0 6,000 12,000 FEET

SCALE

REFERENCE: CITY OF AVENAL GENERAL PLAN.

1 36.074 -120.093

AV

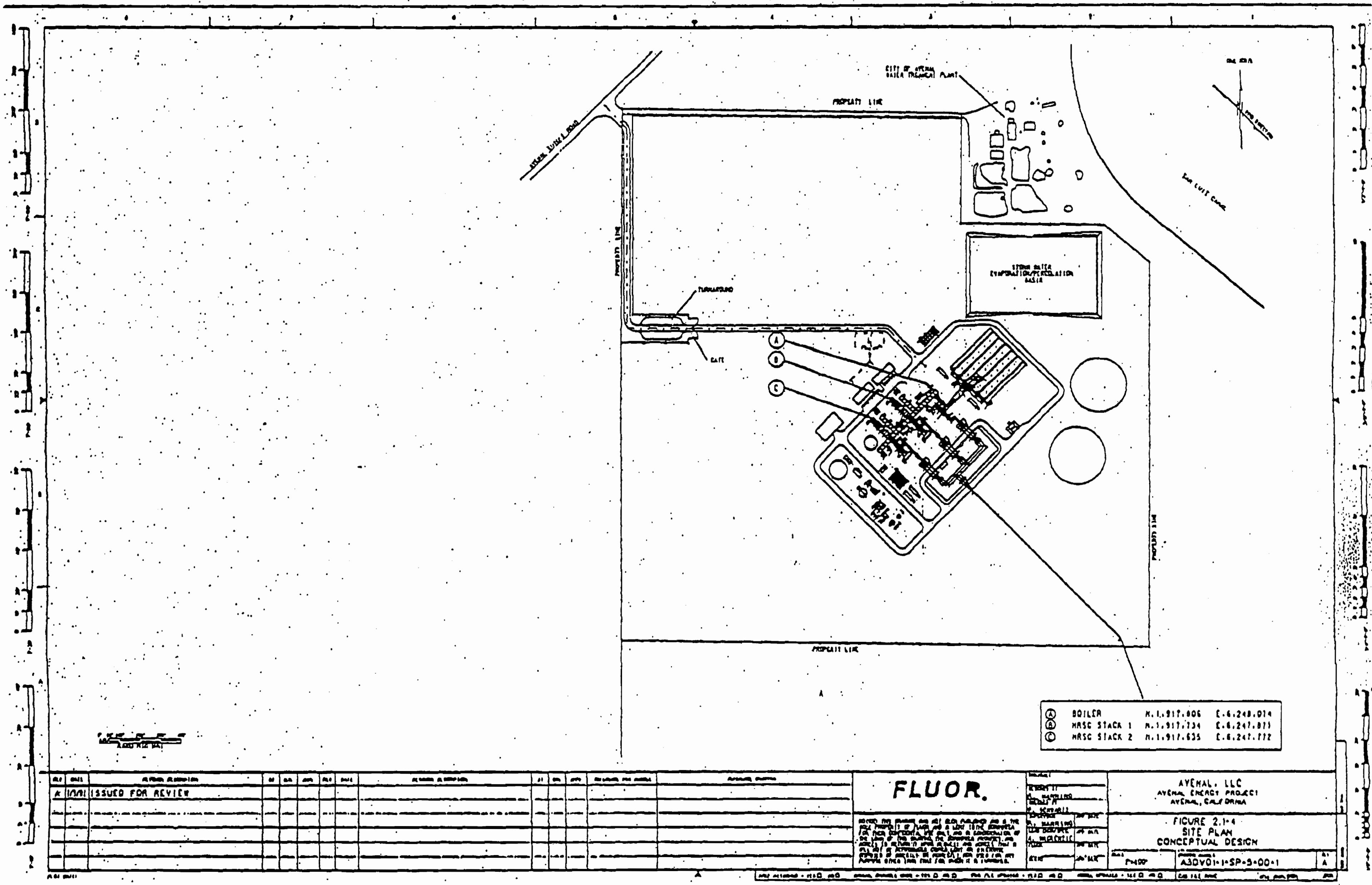
SITE LOCATION

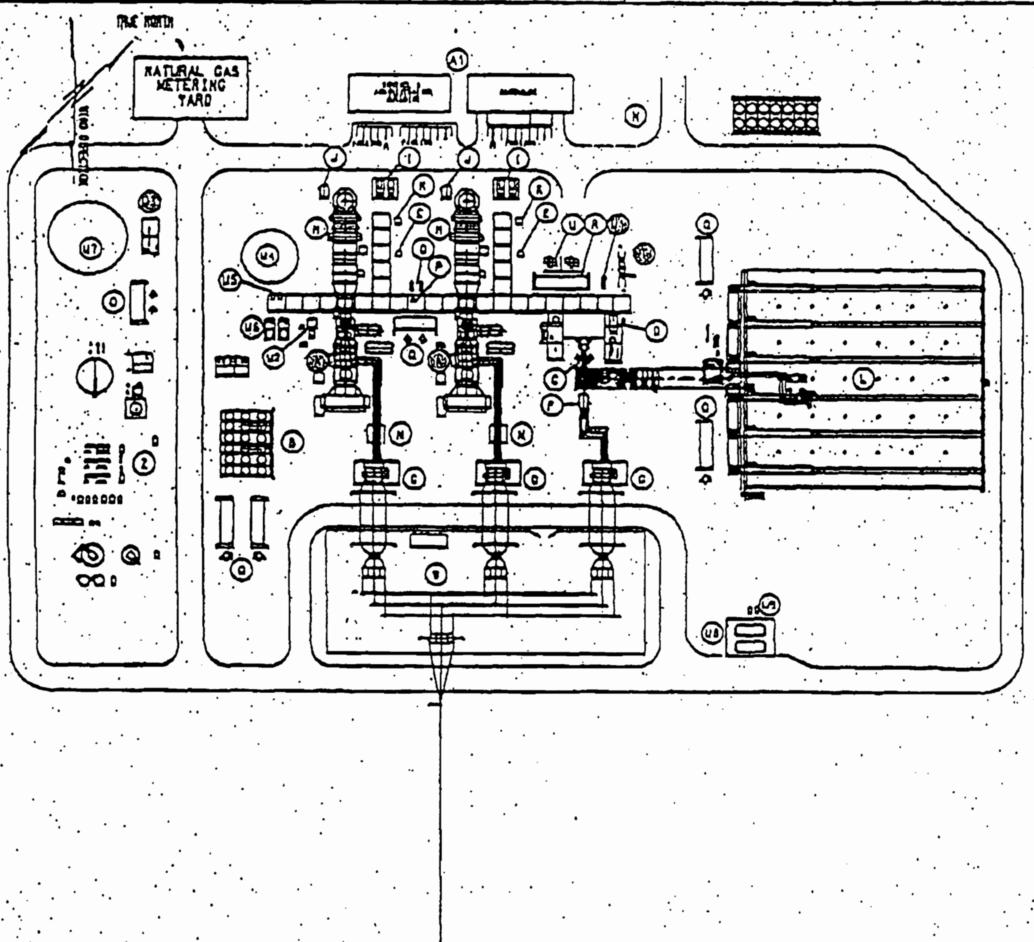
② Rd crosses horiz rd near development

36.109 -120.0486

FEDERAL POWER AVENAL, LLC

AVENAL ENERGY	**FIGURE 2.0-2**


CITY OF AVENAL WATER TREATMENT PLANT
PROPERTY LINE
SAN LUIS CANAL
STORM WATER EVAPORATION/PERCOLATION BASIN
TURNAROUND
GATE
A
B
C
BOILER N.1,917,806 E.6,248,014
HRSG STACK 1 N.1,917,734 E.6,247,873
HRSG STACK 2 N.1,917,635 E.6,247,772
A 11/01 ISSUED FOR REVIEW
FLUOR.
AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA
FIGURE 2.1-4
SITE PLAN
CONCEPTUAL DESIGN
A3DV01-1-SP-5-00-1
A



MAJOR EQUIPMENT LIST

A GAS TURBINE GENERATOR
B INLET AIR CHILLERS
C STEAM TURBINE
D STG LUBE OIL SKID
E HRSG BLOW DOWN DRUM
F STG GENERATOR
G MAIN TRANSFORMERS
H HEAT RECOVERY STEAM GENERATOR
I HP/IP BOILER FEED WATER PUMPS
J CONTINUOUS EMISSIONS MONITORING SYSTEM
K HRSG BLOWDOWN SUMP
L AIR COOLED CONDENSER
M GENERATOR BREAKERS
N CLOSED COOLING WATER AIR COOLER
O CIRCULATING COOLING WATER PUMPS
P CLOSED COOLING WATER EXPANSION TANK
Q POWER DISTRIBUTION CENTER (480 V)
R POWER DISTRIBUTION CENTER (4160 V)
S
T AUXILIARY BOILER
U UNIT AUXILIARY TRANSFORMER
V
W SWITCHYARD
X RAW WATER SOFTENER CLARIFIERS (RWSC)
Y RWSC FILTER PRESS
Z ZERO LIQUID DISCHARGE FACILITY (ZLDF)

A1 SEPTIC TANK & LEACH FIELD (IMMEDIATELY NW)
A2 STORM WATER EVAPORATION/PERCOLATION BASIN

UTILITIES

U1 STANDBY DIESEL GENERATOR
U2 OIL/WATER SEPARATOR
U3 FIREWATER PUMP HOUSE
U4 DEMINERALIZED WATER STORAGE TANK
U5 DEMINERALIZED WATER PUMPS
U6 PLANT/INSTRUMENT AIR COMPRESSORS
U7 RAW WATER/FIREWATER STORAGE TANKS
U8 AMMONIA STORAGE TANKS
U9 AMMONIA TRANSFER PUMPS

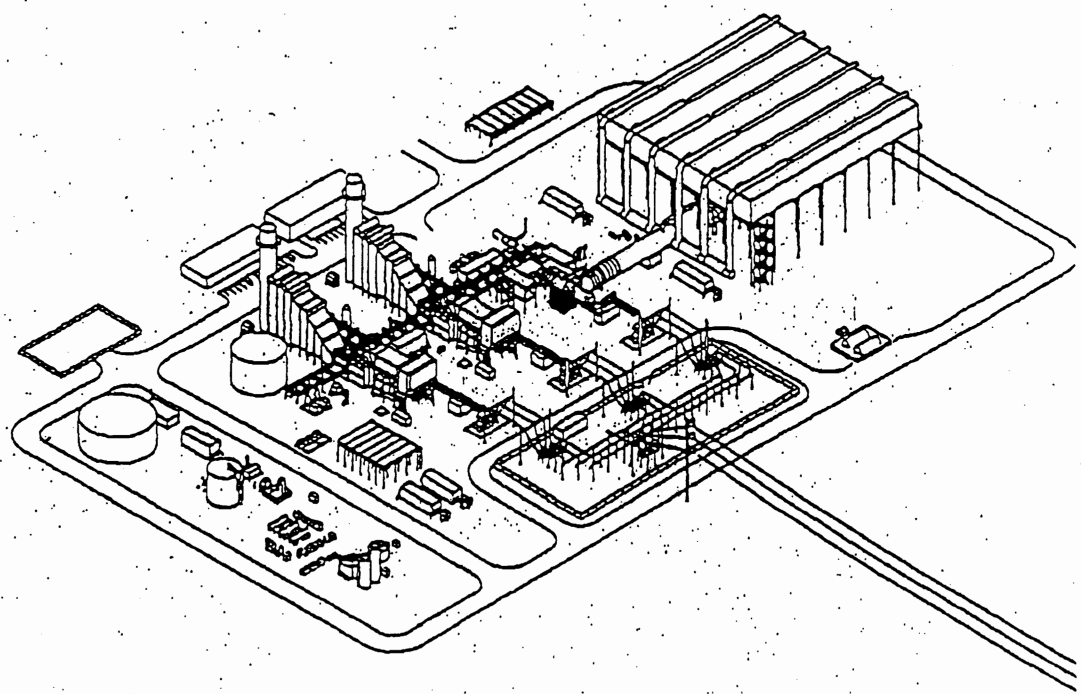
A	7/4/01	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.3-3
PLOT PLAN
CONCEPTUAL DESIGN

P-1261 A30Y01-1-PP-0-00-1 A



REV	DATE	DESCRIPTION
A	[illegible]	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

ISO VIEW
CONCEPTUAL DESIGN

NONE

A30YO1-1-PP-0-00-2

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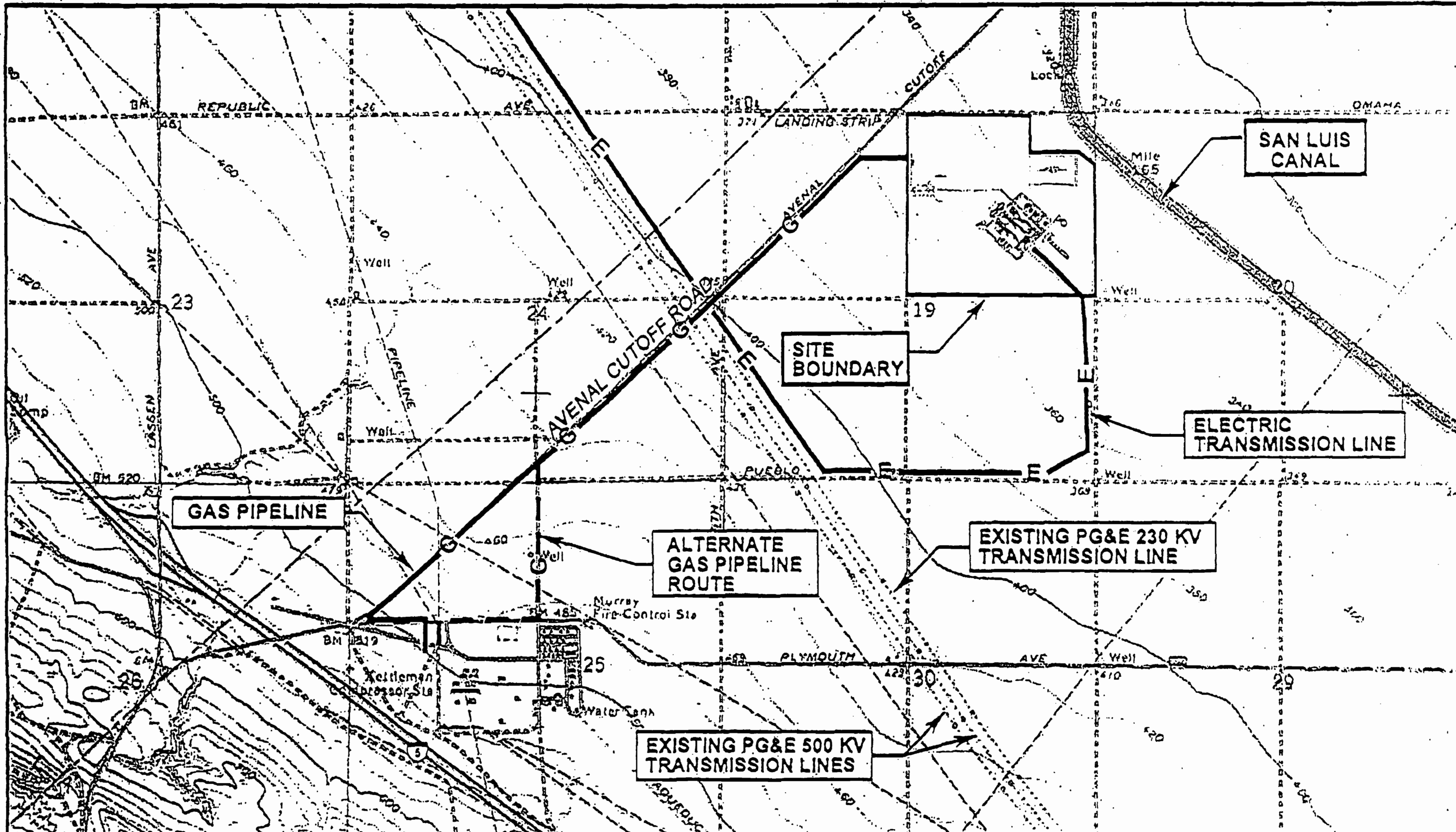

REFERENCE:
U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP OF LA CIMA, CALIFORNIA, DATED 1978.

0 2,000 4,000 FEET
SCALE

NATURAL GAS AND ELECTRICAL INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

AVENAL ENERGY | FIGURE 2.1-1A

ATTACHMENT D

CTG Emissions Data

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

TABLE 6.2-22
MAXIMUM FACILITY FUEL USE, MMBTU (HHV)

Period	Gas Turbines and Duct Burners (each[a])	Auxiliary Boiler	Total Fuel Use (all Units)
Per Hour	2,356.5	37.4	4,750
Per Day	56,555[b]	449[c]	113,111[d]
Per Year	16,176,000[e]	46,650[f]	32,353,000[g]

Notes:
[a] Each of two trains.
[b] Based on 24 hours per day of duct firing.
[c] Based on a startup day, during which the auxiliary boiler would be used 12 hours.
[d] The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).
[e] Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.
[f] Based on 1,248 hours of operation per year.
[g] Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

CTG Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. PM_{10} and SO_2 emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

TABLE 6.2-23
FACILITY STARTUP/SHUTDOWN EMISSION RATES[a]

	NOx	CO	VOC
Startup/Shutdown, lb/hour, average	80	900	16
Startup/Shutdown, lb/~~start~~, hour maximum	160	1,000	16

[a] Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

CTG Emissions During Commissioning

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the NO_x emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, NO_x and CO levels could again be affected.

Noncriteria Pollutant Emissions

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[24] In addition to these nine compounds, the federal Clean Air Act listed 187 to 189[25] substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

[24] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.
[25] Currently 187 substances are listed.

ATTACHMENT D

CTG Emissions Data

Table 8.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

	Case 1	Case 5	Case 9	Case 2	Case 6	Case 10	Case 4	Case 8	Case 12
	101°F	63°F	32°F	101°F	63°F	32°F	101°F	63°F	32°F
	Full Load w/ DB[1]	Full Load w/ DB[1]	Full Load w/ DB[1]	Full Load no DB	Full Load no DB	Full Load no DB	50% Load	50% Load	50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.5	345.6	359.5	144.1	168.6	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.6	130.6
Plant Gross Power Output, MW	635.6	618.3	613.7	517.2	521.7	537.2	262.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	506.5	525.5	250.3	286.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	96.2	102.2
DBs Fuel Flow, kpph	49.0	39.8	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	2,356.5	2,248.6	2,211.8	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	1,044,365	1,025,495	1,069,836	1,051,631	1,037,822	1,071,653	620,528	644,316	666,146
Stack Temp, °F	195.3	184.9	189.0	207.4	198.8	200.9	180.2	175.8	177.4
Stack exhaust, vol%									
O_2 (dry)	11.40%	11.87%	12.34%	13.76%	13.77%	13.78%	14.46%	14.11%	13.93%
CO_2 (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.08%	3.70%	3.89%	3.89%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
Emissions									
NO_x, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO_x, lb/hr[2]	17.13	16.34	16.06	13.03	13.03	13.47	7.26	8.01	8.51
NO_x, lb/MMBtu (HHV)	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SO_2, ppmvd @ 15% O_2 [3]	0.139	0.139	0.140	0.140	0.140	0.140	0.140	0.140	0.140
SO_2, lb/hr[2,3]	1.66	1.59	1.56	1.27	1.27	1.31	0.71	0.78	0.83
SO_2, lb/MMBtu (HHV)[3]	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O_2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/hr[2]	20.86	19.90	19.56	15.86	15.86	16.39	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	0.0089	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O_2[4]	2.0	2.0	2.0	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/hr[2,4]	5.98	5.68	5.59	3.17	3.17	3.28	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	0.0026	0.0025	0.0025	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
PM_{10}, lb/hr[2,5]	11.81	11.27	10.78	9.00	9.00	9.00	9.00	9.00	9.00
PM_{10}, lb/MMBtu (HHV)[5]	0.0050	0.0050	0.0049	0.0050	0.0050	0.0048	0.0090	0.0081	0.0077
PM_{10}, gr/SCF (dry)[5]	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH_3, ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH_3, lb/hr[2]	35.39	33.57	32.88	26.28	26.25	26.98	14.60	16.08	17.02
CO_2, lb/MMBtu (HHV)[7]	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH_4, lb/MMBtu (HHV)[6]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[6]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr[8]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr[8]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr[8]	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

1/23/2008

1) Includes duct burner firing only up to plant maximum output of 600 MW.

2) All mass flow values reported are on a per stack basis. Plant total mass flows are double these values.

3) All of the assumed 0.25 gr S in 100 acf of the fuel is assumed to be converted to SO_2 with no SO_3 conversion.

4) Based on an assumption that 20% of reported UHC emissions are VOCs.

5) Includes front-half (filterable) portion only. Back-half (condensible) portion is excluded.

6) CH_4 emission factor (kg/MMBtu) = 0.0059

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

7) CO_2 emission factor (kg/MMBtu) = 53.06

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.

8) N_2O emission factor (kg/MMBtu) = 0.0001

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

ATTACHMENT E

SJVAPCD BACT Guidelines 1.1.2, 3.1.4, 3.1.8, and 3.4.2

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 3/14/2002

Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Natural gas fuel with LPG backup		
NOx	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire).	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire).	
PM10	Natural gas fuel with LPG backup		
SO	Natural gas fuel with LPG backup		
VOC	Natural gas fuel with LPG backup		

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.8*

Last Update: 4/4/2002

Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	= or < 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	> or = 80% control efficiency (Rich-burn engine with NSCR, or equal)
NOx	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)		= or > 90% control efficiency (Rich-burn engine with NSCR, or equal)
PM10	Natural gas fuel		
VOC	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	= or > 50% control efficiency (Rich-burn engine with NSCR, or equal)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	
NOx	2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM10	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SOx	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O2	1.5 ppmv @ 15% O2	

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT F

Top Down BACT Analysis
(C-3953-10-1, -11-1, -12-1, -13-1, and –14-1)

Units C-3953-10-1 and –11-1 (Turbines)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with NO_X emissions of 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). The facility has proposed to use an inlet air filtration and cooling system, water injection, and a Selective Catalytic Reduction system on each of these turbines to achieve NO_X emissions of less than or equal to 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 1.5 ppmvd VOC @ 15% O_2
2. 2.0 ppmvd VOC @ 15% O_2

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - <u>Select BACT</u>

BACT for the emission unit is determined to be the use of natural gas fuel or LPG with emissions of less than or equal to 2.0 ppmv @ 15% O_2. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% O_2; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air in inlet filter, lube oil vent coalescer and natural gas fuel or equal. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of an air inlet filter, lube oil vent coalescer and natural gas fuel or equal. Avenal Power Center is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

IV. SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel; or
- Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel. Avenal Power Center has proposed to fire each of the turbines solely on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)
2. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the boiler will not exceed 9.0 ppmv @ 3% O_2. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be NO_X emissions of less than 9.0 ppmvd @ 3% O_2. The facility has proposed NO_X emissions of less than 9.0 ppmv @ 3% O_2. Therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for VOC emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified NO_X emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. Certified NO_X emissions of 6.9 g/bhp-hr or less

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the engine will not exceed 3.4 g/bhp-hr. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be Certified NO_X emissions of 6.9 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 6.9 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Catalytic Oxidation

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. Catalytic Oxidation
2. Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

Step 5 - Select BACT

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 288 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

<u>Units C-3953-14-1 (Natural gas IC engine powering electrical generator)</u>

I. NO_X Top-Down BACT Analysis

Step 1 - <u>Identify All Possible Control Technologies</u>

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- NO_X emissions of $\leq$ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- $\geq$ 90% control efficiency (rich-burn engine with NSCR or equal)

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

All control options listed in step 1 are technologically feasible.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

The following options are ranked based on their control efficiency:

1. $\geq$ 90% control efficiency (rich-burn engine with NSCR or equal)
2. NO_X emissions of $\leq$ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

Step 4 - <u>Cost Effective Analysis</u>

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

1. $\geq$ 90% control efficiency (rich-burn engine with NSCR or equal)

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_X reduction is $9,700 per ton of NO_X reduced.

Based upon the fact that there are only a few existing IC engine installations within this class and category of source that operate with emissions of $\leq$ 1.0 g NO_X/hp-hr, the District will assume that the Industry Standard will be 2.8 g NO_X/hp-hr (lb/MMBtu converted to g/hp-hr, Attachment I), pursuant to a AP-42 (07/00) values of uncontrolled four-stroke lean burn IC engines (< 90% load).

AP-42 publishes an uncontrolled NO_X value of 2.21 lb/MMBtu (90 – 105% load), which is approximately 13.4 g NO_X/hp-hr. Several major engine manufacturers were surveyed (Cummins, Caterpillar, and Waukesha) and the District found that lean burn engines sold by these engine manufacturers do not emit emissions close to the uncontrolled value for 90 – 105% load, published in AP-42. Based on the discussions with service representatives of each engine manufacturer, emissions were closer to the AP-42 value published for the < 90% load, which was around 2.5 g NO_X/hp-hr than it was for the value published for the 90 – 105% load. Therefore, industry standard for lean burn natural gas-fired emergency IC engine will be 2.8 g NO_X/hp-hr.

The proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>NO_X (annual):</u>

$$\frac{2.8\ \cancel{g}}{\cancel{hp\text{-}hr}} \left| \frac{860\ \cancel{hp}}{1} \right| \frac{lb}{453.6\ \cancel{g}} \left| \frac{50\ \cancel{hr}}{year} \right. = 265\ lb\ NO_X/year$$

PE_{NOx} = 265 lb NO_X/year = 0.1325 tons NO_X/year

The proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a NO_X control efficiency of $\geq$ 90% can be calculated as:

<u>NO_X (annual):</u>

$$\frac{7.4\ \cancel{g}^{(1)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.9)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 70\ lb\ NO_X/year$$

PE_{NOx} = 70 lb NO_X/year = 0.035 tons NO_X/year

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

CE_{alt} = $(Cost_{alt} - Cost_{basic}) \div (Emission_{basic} - Emission_{alt})$

[1] Pursuant to AP-42 (07/00) the NO_X value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

where,

CE_{alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

$Cost_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

$Emission_{basic}$ = the emissions from the proposed basic equipment, without BACT.

$Emission_{alt}$ = the emissions from the alternate basic equipment

The District conducted research to determine the appropriate cost information for installing a rich burn IC engine with a Non-Selective Catalytic Reduction System versus the cost information for installing a uncontrolled lean burn IC engine. Based on information from various engine manufacturers, the initial costs for installing an uncontrolled rich burn engine versus an uncontrolled lean burn engine would be minimal. The main difference in cost would be incurred in the installation of the NSCR system and the air to fuel ratio controller to the rich burn IC engine.

According to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" (pgs. V-2 & V-3), the approximate capital cost for installing a NSCR system for a 1,000 hp engine would be approximately $28,000, the capital cost for installing an air to fuel ratio controller would be $5,300, and the overall installation cost would be $2,500. The CARB RACT/BARCT document also states the annual cost for operating and maintenance is between $8,000 – 10,000, but these values are assuming full time operation. Since the proposed installation will be limited only to emergency operation and testing and maintenance, a conservative assumption of $1,000 per year will be utilized for this evaluation.

Per District BACT Policy, the equivalent annual capital cost is calculated as follows:

$$A (\$/yr) = P \times [i \times (1 + i)^n] \div [(1 + i)^n - 1]$$

Where:
- A = Equivalent annual capital cost of the control equipment
- P = Present value of the control equipment including installation
- i = interest rate (10% used as default value)
- n = equipment life (10 years used as default value)

Using a total capital cost of $35,800 in the above equation results in an equivalent annual cost of $5,826/year. Adding this equivalent annual cost to the annual operating cost of $1,000/year, the ($Cost_{alt}$ - $Cost_{basic}$) is equal to $6,826/year. It should be noted that the operating the rich burn IC engine versus a lean burn IC engine would result in an efficiency loss and would potentially result in higher annual fuel expenses. These costs will be set aside for the present and only a partial cost analysis will be performed.

District BACT policy also requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a NSCR system will control NO_X, CO, and VOC emissions. Therefore, the MCET is calculated as follows:

$$\text{MCET (\$/yr)} = (E_{NOx} \times T_{NOx}) + (E_{CO} \times T_{CO}) + (E_{VOC} \times T_{VOC})$$

Where:
E_{NOx} = tons-NO_X controlled/yr
E_{CO} = tons-CO controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_X
= \$9,700/ton-NO_X
T_{CO} = District's cost effectiveness threshold for CO
= \$300/ton-CO
T_{VOC} = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

Since this BACT cost effectiveness analysis is analyzing alternate basic equipment with a control technology which controls multiple pollutants; in order to calculate the cost effectiveness for the alternate basic equipment, the District will take the MCET and compare that value with the ($Cost_{alt}$ – $Cost_{basic}$), to determine if this control technology is cost effective.

To determine E_{CO}, the District has to establish what Industry Standard is for CO emissions. As detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for CO emissions @ < 90% load (1.83 g CO/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>CO (annual):</u>

$$\frac{1.83\ \cancel{g}}{\cancel{hp\text{-}hr}} \cdot \frac{860\ \cancel{hp}}{1} \cdot \frac{lb}{453.6\ \cancel{g}} \cdot \frac{50\ \cancel{hr}}{year} = 173\ \text{lb CO/year}$$

PE_{CO} = 173 lb CO/year = 0.0865 ton CO/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB (pg. B-20), the CO control effectiveness from a NSCR system is greater than 80%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a CO control efficiency of ≥ 80% can be calculated as:

<u>CO (annual):</u>

$$\frac{11.6\ \cancel{g}^{(2)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.8)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 220\ lb\ CO/year$$

PE_{CO} = 220 lb CO/year = 0.11 ton CO/year

As demonstrated above, the CO emissions from the rich burn IC engine with a NSCR system are higher than the uncontrolled CO emissions from the lean burn IC engine. Therefore, CO will not be included in the MCET calculations.

To determine E_{VOC}, the District has to establish what Industry Standard is for VOC emissions. Again, as detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for VOC emissions (0.39 g VOC/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>VOC (annual):</u>

$$\frac{0.39\ \cancel{g}}{\cancel{hp\text{-}hr}} \left| \frac{860\ \cancel{hp}}{1} \right| \frac{lb}{453.6\ \cancel{g}} \left| \frac{50\ \cancel{hr}}{year} \right. = 37\ lb\ VOC/year$$

PE_{VOC} = 37 lb VOC/year = 0.0185 ton VOC/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB, the VOC control effectiveness from a NSCR system is greater than 50%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a VOC control efficiency of ≥ 50% can be calculated as:

<u>VOC (annual):</u>

$$\frac{0.10\ \cancel{g}^{(3)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.5)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 5\ lb\ VOC/year$$

PE_{VOC} = 5 lb VOC/year = 0.0025 ton VOC/year

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[2] Pursuant to AP-42 (07/00) the CO value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)
[3] Pursuant to AP-42 (07/00) the VOC value for uncontrolled four-stroke rich burn IC engines. (lb/MMBtu converted to g/hp-hr, Attachment I)

Calculating for the MCET derives the following:

E_{NOx} = 0.1325 tpy – 0.035 tpy = 0.0975 tpy
E_{VOC} = 0.0185 tpy – 0.0025 tpy = 0.016 tpy

MCET (\$/yr) = (0.0975 x \$9,700) + (0.016 x \$5,000) = \$1,026/year

As presented above, ($Cost_{alt}$ – $Cost_{basic}$) is equal to \$6,826/year.

This value is greater than the MCET; therefore, it has been determine that the installation of a rich burn IC engine with a NSCR system as alternate basic equipment is not cost effective using just the partial cost analysis.

2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

The applicant has proposed that the NOx emissions from the engine will not exceed 1.0 g/bhp-hr. This is the highest ranking remaining control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - <u>Select BACT</u>

BACT for the emission unit is determined to be NO_X emissions of 1.0 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 1.0 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-14-1 (Natural gas IC engine powering electrical generator)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the engine will be equipped with an oxidation catalyst with 90% control of VOC emissions. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the used of an oxidation catalyst with 90% control of VOC emissions. The facility has proposed to install an oxidation catalyst with 90% control of VOC emission. Therefore, BACT is satisfied.

ATTACHMENT G

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Unified Air Pollution Control District

MEMORANDUM

DATE: June 14, 2014

TO: Derek Fukuda, AQE—Permit Services

FROM: Leland Villalvazo, SAQS—Technical Services

SUBJECT: Revised NO_2 1-hour NAAQA Assessment for Avenal Power Center

Technical Services was requested to revise the RMR and AAQA assessment performed for project C-1011324, dated June 25, 2002, to lower the NOx and CO annual emission levels.

A review of the previous project indicated that the major item of concern was the 1-hour standard for NO_2. The previous assessment was based on the State standard of 339 ug/m^3 whereas the new federal standard 188.68 ug/m^3. The assessment contained in this memo will primarily address the new federal NO_2 NAAQS and any updates needed to the previous RMR assessment.

Background:
EPA has revised the primary NO_2 NAAQS in order to provide requisite protection of public health. Specifically, EPA has established a new 1-hour standard at a level of 100 ppb (188.68 ug/m^3), based on the 3-year average of the annual 98th percentile of the daily maximum 1-hour concentrations, to supplement the existing annual standard. EPA has also established requirements for NO_2 monitoring network that will include monitors at locations where maximum NO_2 concentrations are expected to occur, including within 50 meters of major roadways, as well as monitors sited to measure the area-wide NO_2 concentrations that occur more broadly across communities.

The final rule was signed on January 22, 2010. The effective date of the new 1 hour standard is 60 days after the final rule has been published in the Federal Register. The final rule was published in the Federal Register on Feb 9, 2010. The effective date is April 12, 2010.

Results:
Based on guidance from EPA dated February 25, 2010, the District has updated the AAQA assessment to include the new NO_2 1-hour standard, see below. The results follow the procedure outlined in the District's interim draft guidance document entitled "Modeling Procedure to Address The New Federal 1 Hour NO_2 Standard".

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	**P**	13.58
Tier IV	**140.37**		140.37	188.68	**P**	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	**P**	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Conclusion

Based on the updated RMR, the risk from this facility is less than 10 in one million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed below must be included for the proposed unit(s).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

Conditions

1. PM_{10} emission rate shall not exceed **0.059 g/HP-hr (note method) for the 288 hp engine** (C-3953-13-1).

2. The 860 hp engine (C-3953-14-1) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **50 hours per year**.

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	P	13.58
Tier IV	**140.37**		140.37	188.68	P	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	P	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Diesel I.C. Engines (DICE)
Screening Risk Tool

Project Information

Region: C | Facility ID: 3953 | Unit #: 13-1

Project #: 110751

Date: 7/14/2010

Met Station

District	SJVAPCD
Met Site	HANFORD
Model Type	RURAL
Year:	2008

Engine Data

BHP:	288
% Load:	100
PM10 EF (g/BHP):	0.059
Hours / Yr:	100
Lbs / Yr:	3.75

Convert to G/BHP

Convert to G/KW

Update Emissions

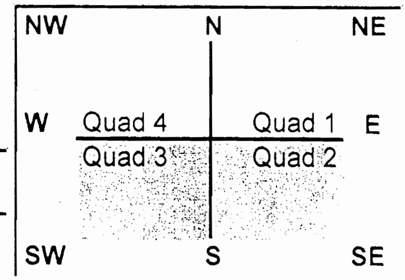
Receptor Data

Quad: QUAD 1

Distance(m): 50

Miles: | Feet:

Yards: | 10th Mi:



Cancer Risk

	Resident Risk:	Maximum Res. Risk
In a Million	**0.24**	**1.98**
Worker Adjustment Factor %		37.91
	Worker Risk:	**Maximum Worker Risk**
In a Million	**0.09**	**0.75**

Quad: 2

Distance: 50

Calculate Risk

Print Form

New | **View Eng Data** | **SAVE** | **Close Form**

14-1

Print Worksheet

INTERNAL COMBUSTION (NG)
EMISSION FACTORS
(LBS. / MMCF)

FACILITY NAME:
DATE:

Priority Score 0.092999134

Receptor Distance: 1206

Total hrs. of operation 50.00 | MMCF/HR 0.0071 | MMCF/YR 0.36

POLLUTANT	EMISSION FACTOR (MMCF/HR) <1000	>1000	TURBINE	Acute REL	Chronic REL	Cancer URF
Acetaldehyde	0.944	1.1328	0.037	0	9	2.70E-06
Acrolein	0.3783	0.454	0.009	0.19	2.00E-02	0
Benzene	3.257	3.9084	0.0113	1300	71	2.90E-05
Formaldehyde	32.4963	38.9956	0.094	94	3.6	6.00E-06
Naphthalene	0.1785	0.1785	0.0008	0	14	0
PAH's	0.0179	0.0179	0.0002	0		1.70E-03
Propylene	16.2259	19.4711	1.0522	0	0	0
Toluene	1.1145	1.3374	0.0726	37000	200	0
Xylenes	0.4048	0.4858	0.0289	22000	300	0
Ethyl Benzene	0.3257	0.3908	0.0132	0	0	0
Hexane	0.7491	0.8989	1.75	0	0	0

	<1000 EMISSION FACTORS	LBS./HR.	G/SEC	LBS./YR.	G/SEC	Acute Score	Chronic Score	Carcinogenic Score	Non-Carcinogenic Score
Acetaldehyde	0.944	6.70E-03	**8.45E-04**	3.35E-01	**4.82E-06**	0	0.11170667	0.001538201	0.111706667
Acrolein	0.3783	2.69E-03	**3.39E-04**	1.34E-01	**1.93E-06**	21.204711	20.144475	0	21.20471053
Benzene	3.257	2.31E-02	**2.92E-03**	1.16E+00	**1.66E-05**	0.0266823	0.048855	0.057002386	0.048855
Formaldehyde	32.4963	2.31E-01	**2.91E-02**	1.15E+01	**1.66E-04**	3.6817616	9.61348875	0.117669102	9.61348875
Naphthalene	0.1785	1.27E-03	**1.60E-04**	6.34E-02	**9.12E-07**	0	0.01357875	0	0.01357875
PAH's	0.0179	1.27E-04	**1.60E-05**	6.35E-03	**9.15E-08**	0	0	0.018364505	0
Propylene	16.2259	1.15E-01	**1.45E-02**	5.76E+00	**8.29E-05**	0	0	0	0
Toluene	1.1145	7.91E-03	**9.98E-04**	3.96E-01	**5.70E-06**	0.0003208	0.00593471	0	0.005934713
Xylenes	0.4048	2.87E-03	**3.62E-04**	1.44E-01	**2.07E-06**	0.000196	0.00143704	0	0.00143704
Ethyl Benzene	0.3257	2.31E-03	**2.92E-04**	1.16E-01	**1.66E-06**	0	0	0	0
Hexane	0.7491	5.32E-03	**6.71E-04**	2.66E-01	**3.83E-06**	0	0	0	0

San Joaquin Valley Unified Air Pollution Control District

MEMORANDUM

DATE: June 25, 2002

TO: Errol Villegas, SAQE—Permit Services

FROM: Esteban Gutierrez, AQS—Technical Services

SUBJECT: AAQA and RMR Modeling request for Duke energy Avenal LLC.

As per your request, Technical Service performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR for, two turbines, two IC engines, nineteen (19) cooling towers and a boiler for a power plant. The engineer supplied the maximum fuel rate as well as process rates for all of the units described above. ISCST3 model was used to determine dispersion value for cancer risk exposure.

The results from the RMR modeling runs and Criteria Pollutant Modeling are as follows:

RMR Modeling Results

REFINED HRA SUMMARY			
Device	**(2) Turbines**	**Boiler**	**(3) 4 cell tower**
Fuel	**NG**	**NG**	
Prioritization Score	0.8242	.0107	N/A
Cancer Risk	N/A	N/A	N/A
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
TBACT Required?	No	No	No

REFINED HRA SUMMARY			
Device	**7 cell tower**	**300 Hp ICE**	**660 HP ICE**
Fuel		**Diesel**	**Diesel**
Prioritization Score	N/A	N/A	N/A
Cancer Risk	N/A	2.01E-6	1.00E-6
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
Maximum operating Hrs		200	38
TBACT Required?	No	Yes	No

Criteria Pollutant Modeling Results*
Values are in ug/m^3

	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass***	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass**	Pass**

*Results were taken from the attached PSD spreadsheet.
**The criteria pollutants noted by a double asterisk (**) are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). Operating time for 24 hour risk was adjusted for PM10 levels.
*** Passing score was obtained from running OLM (Ozone Limiting Method.)

(2) NG Turbines Stack Parameters			
Source Type	Point	**Process Rate (T1) MMbtu/yr**	16,958,390
Stack Height (m)	44.2	**Process Rate (T2) MMbtu/yr**	20,582,010
Stack Diam. (m)	5.49	**Hours of operation yr (T1)**	8400
Gas Exit Velocity (m/sec) T1	20.4	**Hours of operation yr (T2)**	8760
Stack Gas Temp (°K)	356	**Receptor Distance (m)**	1609
Location Type	Rural		

7 Cell Cooling Tower Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	13.7	**Process Rate Gal/Yr**	57,153,744,000
Stack Diam. (m)	9.64	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	8.10	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

(3) 4 Cell Cooling Towers Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	16.08	**Process Rate Gal/Yr**	5,308,560,000
Stack Diam. (m)	3.57	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	11.46	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

Boiler Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	11.28	**Process Rate MMbtu/yr**	93,500
Stack Diam. (m)	0.812	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	12.2	**Hours of operation**	2500
Stack Gas Temp (°K)	476		

Diesel Engine (300 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.13	**Max Operating (hr/yr)**	**100**
Gas Exit Velocity (m/sec)	67.1	**Fuel Type**	Diesel
Stack Gas Temp (°K)	716	**PM10 g/bhp-hr**	0.09

Diesel Engine (660 Hp)			
Source Type	Point	Closest Receptor (m)	1609
Stack Height (m)	3.04	Location Type	RURAL
Stack Diam. (m)	0.23	Max Operating (hr/yr)	38
Gas Exit Velocity (m/sec)	45.0	Fuel Type	Diesel
Stack Gas Temp (°K)	799	PM10 g/bhp-hr	0.4

Conclusion:

The Criteria modeling runs indicate that the emissions from the proposed equipment will not have an adverse impact on the State and National AAQS. Therefore, no further modeling will be required to demonstrate that the AAQS or EPA's level of significance would be exceeded.

The carcinogenic risk for the 300 hp engine is 2.01E-06, which is below the maximum allowable risk of 10 in a million for diesel IC engines emitting ≤ 0.149g PM_{10}/bhp/hr. The risk for the 660 hp engine is 1.00E-06 which is the allowable risk of one in a million for engines emitting > 0.149g PM_{10}/bhp/hr. Therefore, **the project is approved for permitting, and TBACT is required for the 300 hp engine.** In order to assure compliance with the assumptions made for the risk management review the following conditions listed on the PTO are required:

1. Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in these engines.

2. PM_{10} emission rate shall not exceed **0.09 g/HP-hr (note method) for the 300 hp engine** (C-3953-8-0).

3. PM_{10} emission rate shall not exceed **0.40 g/HP-hr (note method) for the 660 hp engine** (C-3953-9-0).

4. The exhaust stacks shall not be fitted with a rain caps, or any other similar devices, that impedes vertical exhaust flow.

5. The 300 hp engine (C-3953-8-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **100 hours per year**.

6. The 660 hp engine (C-3953-9-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **38 hours per year**.

7. The 660 hp engine (C-3953-9-0) shall not operate more than **7 hours in any rolling 24 hr period during maintenance, testing, and required regulatory purposes.**

ATTACHMENT H

_SO_X for PM_{10} Interpollutant Offset Analysis_

SO_X for PM_{10} Interpollutant Offset Analysis
Avenal Power Center, LLC

Facility Name:	Avenal Power Center, LLC	Date:	June 30, 2010
Mailing Address:	500 Dallas Street. Level 31 Houston, TX 77002	Engineer: Lead Engineer:	Derek Fukuda Joven Refuerzo
Contact Person:	Jim Rexroad		
Telephone:	(713) 275-6147		
Application #:	C-3953-10-1, -11-1, -12-1, -13-1, and -14-1		
Project #:	C-1100751		
Location:	NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032		
Complete:	March 18, 2010		

I. Proposal

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 562.3 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

In addition, Avenal Power Center, LLC has proposed to limit the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year.

Facility C-3953 will become a major source for NO_X, VOC, and PM_{10}. There will be an increase in emissions for all pollutants and offsets are required for NO_X, VOC, and PM_{10} emissions.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (9/21/06) (Section 3.30 and 4.13.3.2)

III. Process Description

Combined-Cycle Combustion Turbine Generators
Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)
The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners
Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator
The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler
One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump
Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The

diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

IV. Equipment Listing:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

V. Interpollutant Offset Ratio Proposal SO_X for PM_{10}

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM_{10} precursor ERCs to offset PM_{10} increases:

> *4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.*
>
> *4.13.3.2 Interpollutant offsets between PM10 and PM10 precursors may be allowed.*

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-PM_{10} relationship given the atmospheric chemistry and the meteorology of the locale).

The SO_X for PM_{10} interpollutant ratio of 1.000:1 is based on District analysis (see Appendix A). The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall SO_X for PM10 offset ratio of 1.000 x 1.5 = 1.5:1 is valid for project C-1100751.

IV. Project Offset Calculations

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A[1]	11.78	8.91	8.91	23.56
SO_X	N/A[7]	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A[8]	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A[8]	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

c. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based

[1] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 $\cancel{gr\text{-}S}$/100 $\cancel{dscf}$) x (1 $\cancel{lb\text{-}S}$/7000 $\cancel{gr}$) x (64 lb SO_X/32 $\cancel{lb\text{-}S}$) x (1 $\cancel{scf}$/1013 $\cancel{Btu}$) x (10^6 $\cancel{Btu}$/MMBtu)
= 0.001 lb-SO_X/MMBtu

CTG w/o Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **1.86 lb-SO_X/hr**

CTG w/ Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **2.36 lb-SO_X/hr**

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

ii. C-3953-12-0 (Boiler)

The PM_{10} potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.19	2.2	58	233

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The PM_{10} emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.04	0.9	0.5	2

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The PM_{10} emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.06	1.5	1	3

Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
C-3953-13-1			12	2	0	0
C-3953-14-1			31	3	1	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Total Emissions to be Offset

Pursuant to District Rule 2201, Section 4.6, emission offsets shall not be required for emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Therefore the emission from the diesel-fired fire water pump and the natural gas-fired emergency standby generator are not required to be offset.

Emission to be Offset (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,179**	**161,545**	**33,520**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Offset Calculations:

PM_{10}:

SSPE2 (PM_{10}) = 161,545 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(161,545 – 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
33,087	33,086	33,086	33,086

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year
= 99.26 ton/yr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
49,630	49,629	49,629	49,630

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-896-4	80	80	80	80
ERC #N-721-4	0	0	3,215	0
ERC #N-723-4	0	0	985	0
ERC #S-2791-5	92,179	23,666	69,157	96,288
ERC #S-2790-5	12,862	491	0	8,499
ERC #S-2789-5	6	14	12	8
ERC #S-2788-5	5	7	3	6
ERC #N-762-5	21,000	21,000	21,000	21,000

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Appendix A). This interpollutant ratio has been evaluated by the District's modeler, James Sweet, Air Quality Project Planner. Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

V. Conclusion

Approve use of an overall SO_X for PM_{10} interpollutant offset ratio of 1.5:1 (1.000 x 1.5).

VI. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-1, -11-1, -12-1, -13-1, and -14-1 with a SO_X for PM_{10} interpollutant offset ratio of 1.000:1.

Appendix

A: District Review and Approval

Appendix A

District Review and Approval

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.	2008 PM2.5 Plan, Appendix F
	Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:** 2009 Interpollutant ratio is consistent with current emissions inventories	2008 PM2.5 Plan
	Regional modeling does not show a significant change in chemical relationships through 2014.	*Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

ATTACHMENT I

Additional Supplemental Information

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]
(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	2.21 E+00	A
NO_x[c] <90% Load	2.27 E+00	C
CO[c] 90 - 105% Load	3.72 E+00	A
CO[c] <90% Load	3.51 E+00	C
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	3.58 E-01	C
Methane[g]	2.30 E-01	C
VOC[h]	2.96 E-02	C
PM10 (filterable)[i,j]	9.50 E-03	E
PM2.5 (filterable)[j]	9.50 E-03	E
PM Condensable[k]	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[l]	2.53 E-05	C
1,1,2-Trichloroethane[l]	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene[l]	6.63 E-04	D
1,3-Dichloropropene[l]	<1.27 E-05	E
Acetaldehyde[l,m]	2.79 E-03	C
Acrolein[l,m]	2.63 E-03	C
Benzene[l]	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride[l]	<1.77 E-05	E

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	0.847 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	229.94 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume -> Grams/Brake Horsepower - Hour

ppmv -> g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	230	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
MW (NO_x):	46	as NO_2
MW (CO):	28	
MW (VOC):	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

$$\frac{\text{ppmv}}{1} \cdot \frac{\text{F-factor}}{1} \cdot \frac{MW_{pollutant}}{1} \cdot \frac{20.9}{(20.9 - O_2\%)} \cdot \frac{1}{\text{Conversion \#1}} \cdot \frac{1}{\text{Conversion \#2}} \cdot \frac{\text{Conversion \#3}}{1} \cdot \frac{1}{\text{Engine Eff.}} =$$

for NO_x:

$$\frac{230\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{46\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{1\ \text{lb-mol}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 2.750 g/bhp-hr | 2365 g/hr | 5.21465 lbs/hr | 125 lbs/day

for CO:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{28\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{16\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	2.270 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	616.25 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F		
COAL (ANTHRACITE)	10100 DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780 DSCF/MMBTU	COAL
COAL (LIGNITE)	9860 DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160 DSCF/MMBTU	OIL
GAS (NATURAL)	8710 DSCF/MMBTU	GAS
GAS (PROPANE)	8710 DSCF/MMBTU	GAS
GAS (BUTANE)	8710 DSCF/MMBTU	GAS
WOOD	9240 DSCF/MMBTU	WOOD
WOOD BARK	9600 DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570 DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710 DSCF/MMBTU	GAS

Parts Per Million Volume --> Grams Brake Horsepower - Hour

ppmv --> g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	616	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.286	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NO_x)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

$$\frac{ppmv}{1} \cdot \frac{\text{F-factor}}{1} \cdot \frac{MW_{pollutant}}{1} \cdot \frac{20.9}{(20.9 - O_2\%)} \cdot \frac{1}{\text{Conversion \#1}} \cdot \frac{1}{\text{Conversion \#2}} \cdot \frac{\text{Conversion \#3}}{1} \cdot \frac{1}{\text{Engine Eff.}} =$$

for NOx:

$$\frac{616\ \cancel{parts}}{10^6\ \cancel{parts}} \cdot \frac{8578\ \cancel{dscf}}{\cancel{MMBtu}} \cdot \frac{46\ \cancel{lb}}{\cancel{1\ lb\text{-}mol}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{1\ lb\text{-}mol}}{379.5\ \cancel{dscf}} \cdot \frac{\cancel{MMBtu}}{393.24\ bhp\text{-}hr} \cdot \frac{453.59\ g}{\cancel{lb}} \cdot \frac{1}{35\%} =$$

= 7.365 g/bhp-hr | 6334 g/hr | 13.9662 lbs/hr | 335 lbs/day

for CO:

$$\frac{0\ \cancel{parts}}{10^6\ \cancel{parts}} \cdot \frac{8578\ \cancel{dscf}}{\cancel{MMBtu}} \cdot \frac{28\ \cancel{lb}}{\cancel{1\ lb\text{-}mol}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{lb}}{379.5\ \cancel{dscf}} \cdot \frac{\cancel{MMBtu}}{393.24\ bhp\text{-}hr} \cdot \frac{453.59\ g}{\cancel{lb}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

$$\frac{0\ \cancel{parts}}{10^6\ \cancel{parts}} \cdot \frac{8578\ \cancel{dscf}}{\cancel{MMBtu}} \cdot \frac{16\ \cancel{lb}}{\cancel{1\ lb\text{-}mol}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{lb}}{379.5\ \cancel{dscf}} \cdot \frac{\cancel{MMBtu}}{393.24\ bhp\text{-}hr} \cdot \frac{453.59\ g}{\cancel{lb}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

D'

RECEIVED
JUL 0 3 2008
Permits Srvc
SJVAPCD

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

COPY

July 1, 2008

RE: Certification of Avenal Energy, owned by Avenal Power Center, LLC

I, Stuart Zisman, on behalf of Avenal Power Center, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Avenal Power Center, LLC.
2. This certification is made pursuant to Section 4.15.2 of Rule 2201 of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.
3. To the best of the undersigned's knowledge, relative to Section 4.15.2 of District Rule 2201, Avenal Power Center, LLC. does not currently own, operate or control any Major Stationary Source or federal major modification in the State of California other than the proposed Avenal Energy Project.

Each of the statements herein is made in good faith. Accordingly, it is Avenal Power Center, LLC's understanding in submitting this certification that the SJVUAPCD shall take no action against Avenal Power Center, LLC or any of its employees based on any statement made in this certification.

Stuart Zisman
Vice President
Avenal Power Center, LLC

7/1/08
Dated

Joseph Forbes
Senior Lawyer

ATTACHMENT J

EPA Comments and District Responses

EPA Comments / District Response

The comments (from Gerardo Rios) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

EPA Comments – Letters Dated September 13, 2010

EPA Comment #1:

Applicable federal requirements include thresholds for defining a major source of criteria pollutant emissions. For those sources where emission estimates and/or emission limits are relatively close to the federal thresholds, EPA encourages the following: (a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or (b) a 5-10% buffer between the permitted emission limits and the federal threshold.

The proposed annual NOx emission and CO emission limits are within a margin of less than 5% of the federal annual threshold limit for defining a new major stationary source under the Federal Prevention of Significant Deterioration (PSD) permit program. The threshold is 100 tons per year (tpy) each. If the limits of these pollutants are relaxed, the facility may be subject to the applicable federal requirements, such as the Federal Prevention of Significant Deterioration (PSD) permitting program (See 40 CFR Part 52.21 (r)(4)).

District's Response:

The permitted emissions from this facility are below PSD thresholds. The facility's NO_X and CO emissions limits are included as permit conditions on the PDOC. The facility is also required to maintain records to demonstrate that they do not exceed these emission limits.

In addition, emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #2:

In the "General Calculations" section (See PDOC Page 27, Section VII. C. 5), the District compares the annual emission estimates for regulated pollutants to the major source threshold to determine whether a pollutant is subject to major source requirements for NO_X, CO, VOC, PM_{10}, and SO_X emissions. However,

$PM_{2.5}$, which also is a regulated pollutant, is not included. On May 8, 2008 EPA finalized regulations to implement the NSR program for $PM_{2.5}$. A source that emits or has the potential to emit 100 tpy or more PM2.5 in a nonattainment area is defined as a major stationary source. (Reference 40 CFR Part 51, Appendix S.) We recommend the District include in its evaluation the $PM_{2.5}$ emission estimates with a comparison to the federal nonattainment major source threshold of 100 tpy (or 200,000 pounds per year).

District's Response:

The potential emissions of PM_{10} from the facility are 161,552 lb-PM_{10}/year (Calculated in the PDOC). Using the conservative assumption that all PM_{10} is $PM_{2.5}$, it is clear that the $PM_{2.5}$ emissions from this facility will not exceed the major source threshold of 100 tons/year. However, to avoid any confusion, the District will revise the PDOC to discuss the potential emissions of $PM_{2.5}$ from this operation.

EPA Comment #3:

The proposed annual emissions (calculated on a twelve consecutive month rolling basis) from the facility are 198,840 pounds per year (lb/yr) NO_X and 197,928 lb/year CO. (See PDOC Page 27, Section VII. C. 5) These annual emissions are equivalent to 99.4 tpy of NO_X emissions and 98.9 tpy of CO emissions, both of which are relatively close to the federal PSD permit program applicability threshold of 100 tpy for each ofthese pollutants. A proposed permit condition requiring that annual emissions not exceed these levels has been added to all combustion related equipment. The condition reads as follows:

> *"Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NOx (as N02) -198,840 lb/year; CO -197,928lb/year."*

In a review of the post-project potential to emit annual emission estimates in Sections VII.C.2.i through C.2.iv. (See PDOC Pages 16-26) for each piece of equipment, we noted that the combustion turbine operations contribute the majority of NOx and CO emissions.

Based on discussions with the District, we understand that in addition to the 12-month rolling facility NOx and CO emission limits that are equivalent to 99.4 tpy and 98.9, respectively, the District has made no other changes to the current FDOC permit conditions. These conditions include, but are not limited to, the following: continuous emissions monitoring of NO_X and CO; compilation of emissions on a daily, monthly, 12 consecutive month rolling average, and annual basis; quarterly reporting of excess emissions; and acid rain (40 CFR Part 75) compliance requirements.

At this time, it appears the proposed requirements provide practically and federally enforceable conditions based on our understanding of the proposed revision. However, given that the NO_X permit limit is within less than 1% of the PSD permit threshold and the CO limit is within 1.1% of the PSD permit threshold, we suggest that the District consider requiring Avenal to report more frequently emissions as the actual emissions approach or exceed 90% of the 12-consecutive month rolling average permit limit to assure the 100 tpy threshold is not exceeded.

<u>District's Response:</u>

Emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

<u>EPA Comment #4:</u>

The District concludes on pp. 53-54 of the PDOC that the proposed project will not cause a violation of an air quality standard for NOx, and refers to Appendix G. PDOC Appendix G contains some additional detail on the air quality impact analysis for the I-hour N02 NAAQS, effective April 12, 2010, and states that "the emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS." The following are our comments specific to PDOC Appendix G:

a. SIP-Approved Rule 2201 -The District's approved SIP, in District Rule 2201, Section 4.14.1, provides that modeling used for purposes of determining whether a new or modified stationary source's emissions will cause or make worse the violation of an Ambient Air Quality Standard shall be consistent with the requirements contained in the most recent edition of EPA's "Guideline on Air Quality Models." This EPA guideline is found in 40 CFR Part 51, Appendix w. EPA recently has had occasion to review and comment on the applicant's I-hour N02 NAAQS analysis for the project in the context of the applicant's pending PSD permit application before EPA.

   We recognize that certain aspects of the project for which Avenal seeks a minor source permit vary from the project for which it seeks a PSD permit, in particular, the proposed addition of a facility-wide NOx emissions limit of the equivalent of approximately 99.4 tons per year (tpy) to the minor source permit. However, given that the equipment emitting NOx from the two projects has the same permitted hourly emission rates, many of the comments EPA made concerning consistency with 40 CFR Part 51, Appendix W in reviewing the applicant's l-hour N02 NAAQS analysis for PSD purposes may be relevant to the l-hour N02 NAAQS analysis for this minor source permit as well. We have attached for your consideration our comments dated June 15, 2010 and August 12, 2010 on the l-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes. We would be happy to discuss any issues or questions you may have concerning these comments.

b. EPA Guidance Memorandum -We also note that EPA recently issued guidance relating to modeling for the l-hour N02 NAAQS, with a cover memorandum entitled *Guidance Concerning Implementation of the 1-hour N02 NAAQS for the Prevention of Significant Deterioration Program,* dated June 29, 2010, that included two attached guidance documents, one of which was entitled *Applicability of Appendix W Modeling Guidance for the 1-hour N02 National Ambient Air Quality Standard,* dated June 28, 2010. We understand that the District is aware of this guidance, and we encourage the District to refer to this guidance for further detail on this subject.

c. Assumptions and Decision-making Process -The District's rationale in Appendix G for its conclusion that the project's emissions will not cause or contribute significantly to a violation of the l-hour N02 NAAQS is not clear from the documents provided. For example, the table addressing "Operational" scenarios on page 2 of Appendix G indicates that Tier 1 and Tier 2 impacts are each greater than the N02 NAAQS limit, while Tier III and Tier IV impacts are each below the N02 NAAQS limit. Furthermore, it is unclear how the modeling analysis meets the requirements of Appendix W (See Comment 4.a.) or whether the District intended to follow those requirements for the proposed permit revision. We recommend that the District provide a discussion of which Tier the District is relying upon to support its conclusion, the basis for selecting that Tier, and the modeling inputs, assumptions, etc. for that Tier.

<u>District's Response:</u>

a. *The District has reviewed your comments dated June 15, 2010 and August 12, 2010 on the 1-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes, and has no comments at this time. We did not use Avenal Power's analysis to make determinations of NAAQS impacts, but used our own guidance to perform the NO2 modeling (please see responses below).*
b. *The District has reviewed the documents stated above and developed a modeling guidance to address EPA's memos that were provided to the modelers at EPA Region 9. The District is currently waiting for EPA's*

response to this guidance, and is, in fact, working with EPA, ARB, and CAPCOA on developing statewide policy on how to implement our guidance, or something similar. The Avenal Power project was analyzed under this guidance, and the project was approved under Tier III of that guidance.

c. *The District uses a tiered approach when determining compliance with any NAAQS. This approach is similar to that required by OAQPS in their memos which require that each progressively more accurate tier be used (Tier I-Complete Conversion, Tier II-NO2 Ration and Tier III-OLM) until compliance is demonstrated. This project was approved under Tier III. We believe our guidance is consistence with EPA modeling practices and direction, and as we have stated above, we are patiently awaiting EPA's input on our guidance.*

EPA Comment #5, Joint letter to District and Avenal Power Center, LLC:

Avenal Power Center, LLC (Avenal) recently applied for a minor source New Source Review (NSR) permit from the San Joaquin Valley Pollution Control District (SJVAPCD or District) for the Avenal Energy Project. This permit seeks authority to construct the project with emissions limits below the major source thresholds triggering Clean Air Act (CAA) prevention of significant deterioration (PSD) preconstruction review. On July 28, 2010, SJVAPCD's public notice announcing its Preliminary Determination of Compliance for this minor source permit application was published in the Fresno Bee, triggering a public review and comment period for the proposed permit.

Concurrently, Avenal is seeking a PSD permit from EPA Region 9 for essentially the same project, but with greater emissions exceeding the major source threshold and thereby triggering PSD preconstruction review. The applicant's simultaneous application for both a minor source permit and a major souce PSD permit for the project raises a potential concern about circumvention of PSD preconstruction requirements.

EPA guidance on this subject states:

> Parts C and D of the Clean Air Act exhibit Congress's clear intent that new major sources of air pollution be subject to preconstruction review. The purposes for these programs cannot be served without this essential element. Therefore, attempts to expedite construction by securing minor source status through receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements... If a major source or major modification permit application is filed simultaneously with or at approximately the same time as the minor source construction permit, this is strong evidence of an intent to circumvent the requirements of preconstruction review.

Guidance on Limiting Potential to Emit in New Source Permitting, Terrell E. Hunt and John S. Seitz, dated June 13, 1989, at pp. 13-14.

We recommend that the applicant carefully review the guidance quoted above and other applicable EPA guidance on this topic prior to commencing construction of the project under the minor source permit, should that permit be finalized by the SJVAPCD.

District's Response:

The District disagrees that if Avenal were to construct under a California Energy Commission license that incorporates this minor source Determination of Compliance (DOC), it would be circumvention of the PSD preconstruction review.

Circumvention might occur if a source obtained a minor source permit and soon thereafter sought a PSD permit due to a small increase in emissions, and not as a new source. In this case, Avenal has applied for a PSD permit as a new source. If they construct as a minor source and don't receive a PSD permit, they will have to continue to comply with the minor source limits. However, constructing as a minor source and then obtaining a PSD permit as a new major source and operating in accordance with that PSD permit cannot be viewed as circumvention. Therefore, the EPA process, not the District's minor source permitting process, will determine whether circumvention will occur, and circumvention will not occur if EPA requires a PSD permit if Avenal pursues a permit with emissions above the PSD triggers.

ATTACHMENT K

Green Action Comments and District Responses

Greenaction Comments / District Response

The comments (from Bradley Angel) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Greenaction Comments – Letter Dated September 11, 2010

<u>Greenaction Comment #1:</u>

The Air District failed to conduct a proper and thorough public notice and public participation process. The failure to conduct proper notice and participation processes to the mostly low-income, Latino and Spanish-speaking residents of the nearest communities (Avenal, Huron and Kettleman City) violated the Air District's own environmental justice policy. The Air District's claim that you met your agency's required notice and participation mandates is insufficient as your own environmental justice policy commits the agency to uphold environmental justice.

Failing to notify residents or their organizations, failing to hold a public hearing and failing to provide Spanish-speaking residents equal time to comment as English speakers is a violation of environmental justice and civil rights policies and laws.

We are surprised and disappointed that the Air District would only translate information into Spanish following concerns being raised by Greenaction, and after the comment period already began. On August 20, 2010, we received an email from Dave Warner of the Air District that stated:

> Bradley,
>
> The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at <u>http://www.valleyair.org/General_info/SpanishHmong_Resources.htm</u>

As this email was sent one week into the revised comment period, and as Spanish-speakers had not yet had the opportunity to read information in Spanish, this shows that there has been an unequal opportunity to comment that is improper.

The Air District's notice was inadequate for all of the affected public. No resident or organization representing residents received notice. We only learned of the original comment period from US EPA after it already had begun.

The Air District published a "Notice" in the Fresno Bee, but not in any Kings County or Spanish-language paper.

Even after meeting with the Air District on August 30, 2010 to raise all these concerns, the Air District refused to hold a public hearing, provide proper notice or provide equal opportunities to the Spanish-speaking residents who comprise a major percentage of residents of Avenal, Kettleman City and Huron.

Due to the discriminatory and disproportionate impact on low-income, Latino and Spanish-speakers of the lack of notice and full public participation notice for a project that would emit pollutants into an already over-polluted area, the Air District has violated its own environmental justice policy as well as California Government Code section 11135 and Title VI of the US Civil Rights Act of 1964.

District's Response:

The District complied with all applicable regulatory public noticing requirements with respect to the Avenal Power Center Preliminary Determination of Compliance (PDOC) and in fact took considerable actions that went far beyond statutory requirements. The District properly published notice of the proposed issuance of the PDOC in a newspaper of general circulation, in this case, the Fresno Bee whose distribution does cover the area in question. This notice was published according to our federally approved Rule 2201, which defines the timing and process of such notices. There is no additional direction on public noticing in the District's Environmental Justice Strategy document, contrary to the commenter's claims.

However, we went far beyond our required notification processes for this project, as follows:

1. *We published this notice, as we do all public notices, on the District's website, valleyair.org. This is not required by any rule or regulation, but is part of our continuing effort to make information available and accessible.*

2. *Upon hearing on August 16 of the commenter's concern that he was not notified of the District proposal to issue a DOC, we promptly, on August 18, notified him that we would extend the public noticing period for him and his clients a full additional 30 days from the date that he heard about our proposal. This was not required, since the commenter had not requested that he be informed of our actions on this project, and therefore he was not on record as an interested party. However, in the interests of providing the maximum reasonable opportunity for comment, we offered this accommodation.*

3. *Upon receiving the commenter's subsequent August 19 request for bilingual information on the project, and a public hearing, on August 20 we sent the commenter the following email, from which he quoted an excerpt above. We are providing it in full, below, as it explains our response in some additional detail that was missing from the commenter's excerpt:*

> *Bradley,*
>
> *The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm*
>
> *We would welcome your assistance in distributing it to your Spanish-speaking clients and associates. We will also be pleased to accept comments in Spanish as we have translation capabilities here at the District. As you are aware, we have already extended the public comment period to September 13, 2010, and we believe the above steps will provide you and your Spanish speaking associates ample opportunity to provide comment on our proposal.*
>
> *I just want to make sure you understand the status of this project atthis time as it pertains to the District. The District is taking public comment on a Preliminary Determination of Compliance, which is a recommendation to the California Energy Commission (CEC) that the project will comply with District regulations. We are not aware of any requirement that we hold a meeting for the purpose of receiving verbal comments.*
>
> *We are not going to hold a public hearing on this project at this time. Ours is not a final permitting decision and there is no hearing process associated with it - the CEC has the sole power plant licensing authority in the state of California for power plants over 50 megawatts. They conduct any necessary public hearings associated with such a license. Our action is a certification to the CEC that, if granted, CEC's license would meet our air quality requirements. CEC is able to accept or reject our proposed conditions of approval, or can make air quality permitting decisions contrary to our determination of compliance. In addition, the CEC makes all determinations regarding power plant siting.*

> *Finally, contrary to your contention below, the District is not required to hold a public hearing, by rule or by policy We believe the process described above will assure an efficient, fair, and productive public comment process.*
>
> *Dave Warner*
> *Director of Permit Services*
> *San Joaquin Valley APCD*

In summary, we confirmed that we would prepare a Spanish-language summary of the project and make it available to the commenter for his outreach efforts. We also confirmed our commitment to address any comments we received in Spanish, and we explained the limitations of our role in the permitting process to provide clarity to any potential commenters. None of this was required by our rules and regulations, but was intended to provide additional opportunity for community members to participate in the process.

4. *We then worked through the weekend to create a summary of the project, translate it to Spanish, and post it on the website the very next working day, Monday, August 23.*

5. *Next, on August 24 we agreed to meet with the commenter and any of his clients and community members on August 30. The commenter and other activist organization representatives attended the meeting, but, disappointingly, no independent community members. Again, this meeting was not required by any rule or regulation.*

6. *Finally, we granted another request from another employee of GreenAction that she be provided with an additional day to persuade community members of Avenal and Kettleman City to submit comments, extending the comment period to September 14, for a total public comment period of 53 days instead of the required 30 days. This provided GreenAction the opportunity to persuade community members to submit the comments summarized in the next comment section. And again, there was certainly no rule or regulation that required this accommodation.*

In summary, contrary to the assertions of the commenter, the District not only met all legal requirements but went far beyond them in providing the public opportunities to comment on the Avenal Power Center Project.

Greenaction Comment #2:

The claim by the company and the Air District that there would be substantially less emissions than were stated in the initial permit application dramatically conflicts with earlier information and needs extensive scrutiny including a full public environmental review. If there really would be dramatically lower emissions than first claimed, we wonder why the company did not state this initially, raising questions as to whether the lower, newer estimate is based solely on a desire to avoid a PSD permit requirement and protracted appeals and legal battles.

District's Response:

While no response is necessary, it should be noted that the proposal for lower annual emissions was only possible after rigorous analysis by Avenal Power of actual emissions data from other recently constructed similar power plants. In addition, it seems remarkable that there should be a complaint about a company committing to lower emissions from a facility, regardless of the purpose or intent of the proposal.

Greenaction Comment #3:

The Air District's claim that there would be "zero impact" from the proposed power plant's emissions flies in the face of reality. A huge fossil fuel power plant, no matter how much cleaner than others of its kind, still will have pollution impacts. This "zero impact" claim ignores the fact that this would be a fossil fuel power plant that would have emissions and use fuels that contribute to climate change, would emit a broad range of pollutants, and its emissions would act cumulatively in concert with the many other pollution sources in the area.

The proposed fossil fuel power plant would be close to Kettleman City, a small low-income community of color that is suffering a horrible health crisis involving a large number of birth defects and infant deaths. Even a minor increase in emissions near this community could have severe and unforeseen health impacts due to the current health vulnerability of residents. In addition, the entire San Joaquin Valley already suffers from high rates of asthma, and if built this power plant would emit asthma-triggering pollutants.

District's Response:

The District has searched the PDOC and has not been able to locate the phrase "zero impact".

However, the District has performed a Health Risk Assessment (HRA) as well as an Ambient Air Quality Analysis (AAQA) for this facility. The HRA was performed using the AERMOD model and Hot Spots Analysis and Reporting Program (HARP), and demonstrated that the acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Pursuant to the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit with a cancer risk less than one in one million, and chronic or acute hazard index less than 1.

The AAQA demonstrated that the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. In addition, as shown in the PDOC, the calculated contribution of PM_{10} will not exceed the EPA significance level. Therefore, this project will not cause or contribute significantly to a violation of the State or National AAQS.

Greenaction Comment #4:

This proposed fossil fuel power plant is not needed. Many things have changed since the CPUC originally determined that the Avenal Power Center was needed. As California emerges from an economic recession, the energy landscape has changed. PG&E now has access to more electricity generation than it needs. Last summer, PG&E's territory operated with a 44% reserve margin during summer peak. This extraordinarily high margin is in part due to the CPUC's success at increasing energy efficiency and the demand decrease from the recession. These factors, along with delayed facility retirements and inflated population and energy export assumptions made by the CEC demonstrate that the 600 MWs that the Avenal Power Center would generate are no longer needed. Even PG&E has forecasted a decrease in need. In addition, several large solar projects are to be sited here, and other solar projects are already underway, providing truly clean and renewable energy instead of dirty fossil fuel energy.

Despite all this evidence, Avenal Power Center continues its push for this power plant. The pollution and health effects of this proposed facility are unacceptable when the new capacity is clearly not needed. Finally, allowing unneeded fossil fuel energy would also likely crowd out renewable projects.

District's Response:

The District is not able to take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission.

ATTACHMENT L

NRDC and CRPE Comments and District Responses

National Resources Defense Council (NRDC) and Center on Race, Poverty & The Environment (CRPE) Comments / District Response

The comments (from Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

NRDC and CRPE Comments – Letter Dated September 13, 2010

NRDC and CRPE Comment #1:

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

District's Response:

The District has demonstrated in the PDOC that the proposed facility is in compliance with all applicable NO_X and VOC rules and regulations. It should be noted that these rules and regulations are among the strictest and most stringent in the nation and are designed to protect the health of the residents of the San Joaquin Valley.

NRDC and CRPE Comment #2:

The June, 2009 EPA Statement of Basis And Ambient Air Quality Impact Report for a prevention of significant deterioration (PSD) permit states, at page 14, that emissions of CO and NOx from the Project are expected to be 1,205,400 pounds per year and 288,600 pounds per year, respectively. The July 13, 2010 Revised Preliminary Determination of Compliance for the Project states, at page 1, that emissions of CO will now be 197,928 pounds per year and NOx 198,840 pounds per year, both to be enforced as permit limitations. Conveniently, this would bring both the CO and NOx emissions under the 100-ton limit for major sources under Title V of the Clean Air Act. This change in emission numbers was accomplished with no changes to the setup or operation of the Project itself.

In addition, this sentence occurs relating to the new CO and NOx limits:

> If the annual [CO/NOx] emissions from these units exceed this value, they will be set equal to the proposed facility wide [CO/NOx] emission limit.

Revised PDOC at pages 9 (NOx) and 10 (CO). There are two ways to read this confusing sentence. One is that the sub-100 tons limits are meaningless and will be ignored if exceeded. The other is that APCD is attempting to engage in the type of "flexible permitting" that USEPA has disapproved in Texas. In either case, the federal Clean Air Act has been violated.

District's Response:

The District agrees that the wording in the PDOC is slightly confusing. The intent of the statement was to explain that the potential annual emissions from each of the turbines was calculated based on a stated scenario that was provided by the applicant and that if the unit was not operated exactly in accordance with this scenario, there was the potential for higher NO_X and CO emissions from the unit. However, the total emissions from the facility would not be allowed to exceed the proposed facility wide NO_X and CO emissions limits.

The stated scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, the facility cannot be held to a specific operational schedule. The main point to understand is that the annual emissions from the facility will not exceed the facility wide limit that is stated as a condition on the PDOC, and therefore the impact from the facility's emissions will not be greater than that evaluated by the District.

Attached Letter Addressed to U.S. EPA - Dated October 14, 2009

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comments

The following comments were sent to U.S. EPA on October 14, 2009 from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit on behalf of El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, the Center on Race, Poverty, & the Environment, and the Natural Resources Defense Council. These comments were not sent to the District therefore, the District did not previously respond to the comments. These comments refer to the DOC performed in District project C-1080386, which analyzed the prior, higher-emitting proposal. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments (from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #1:</u>

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year*–$1,600 per person – in the San Joaquin Valley.

<u>District's Response:</u>

This is the same comment that was made in the NRDC and CRPE Letter Dated September 13, 2010 and addressed above. See above for District Response.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #2:</u>

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

<u>District's Response:</u>

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #3:</u>

The Project is expected to emit 80.7 tons/year of PM/PM10. *See* the June 16, 2009 EPA Statement of Basis and Ambient Air Quality Impact Report at p. 14. As we discuss below, we believe that the Project's plan to offset these PM emissions through SOx offsets is invalid under the Clean Air Act. Accordingly, ambient air quality will be impaired by the Project.

As you know, the San Joaquin Valley is in non-attainment for PM2.5. The Project proposes to meet 98% of its PM offset requirements from SOx offsets at a one-to-one ratio. *See* Final Staff Report, Air Quality Table 19. This is highly problematic for a number of reasons.

First, the one-to-one ratio ignores the very different health risks of SOx and PM. The U.S. EPA has found that particulate matter can cause or contribute to increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example; decreased lung function; aggravated asthma; development of chronic bronchitis; irregular heartbeat; nonfatal heart attacks; and premature death in people with heart or lung disease.

Second, the Project applicants should not be allowed to use PM10 as a surrogate for PM2.5 emissions.

<u>District's Response:</u>

The facility is not using PM_{10} as a surrogate for $PM_{2.5}$. The facility has proposed to offset PM_{10} emissions with SO_X ERCs at the District evaluated interpollutant offset ratios. District Rule 2201, Section 4.13.3 allows for the use of interpollutant offsets at ratios based on air quality analysis. The SO_X for PM_{10} offset ratio used in this project is based on the best available science for determining how much PM_{10} SO_X can create. In addition, the facility is not a Major Source for $PM_{2.5}$ emissions; therefore $PM_{2.5}$ requirements will not be addressed in this project.

Attached Letter Addressed to U.S. EPA - Dated October 15, 2009

EarthJustice Comments

The following comments were sent to U.S. EPA on October 15, 2009 from Paul Cort of EarthJustice. These comments were not sent to the District therefore, the District did not respond to the comments. These comments refer to the DOC performed in District project C-1080386. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments from Paul Cort regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

EarthJustice Comment #1:

Commenter's find it stunning that the proposed permit does not even mention CO2 emissions or controls. EPA is well aware that the Environmental Appeals Board ("EAB") has returned multiple PSD permits for failing to consider whether CO2 is a pollutant "subject to regulation" under the Clean Air Act. *See In re Deseret Power Elec. Coop.*, PSD Appeal No. 07 - 03 (EAB Nov. 13, 2008); *In re Northern Mich. University Ripley Heating Plant*, PSD Appeal No. 08 - 02 (EAB Feb. 18, 2009). In light of these decisions, EPA Region 9 also withdrew portions of the PSD Permit issued to Desert Rock Energy Company in order to reconsider the issue of whether CO2 is a pollutant subject to regulation. Yet EPA proposes a PSD permit for another power plant that will emit over 1.7 million tons of CO2 each year without any discussion of these contentious issues whatsoever. EPA must revise the proposed permit to explain EPA's position on BACT for CO2 so that the public can comment on the control levels selected or EPA's rationale for refusing to impose such controls.

District's Response:

This is the same comment that was made in the NRDC and CRPE Letter dated September 13, 2010 and addressed above. See above for District Response.

EarthJustice Comment #2:

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

District's Response:

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

EarthJustice Comment #3:

The Proposed Permit Fails to Demonstrate that the Avenal Project Will Not Cause or Contribute to Violations of National Ambient Air Quality Standards for Ozone and Fine Particulate Matter.

District's Response:

The facility is not a Major Source for $PM_{2.5}$; therefore $PM_{2.5}$ (fine particulate matter) requirements will not be addressed in this project.

There is no EPA approved model capable of accounting for the photochemical complexities of regional ozone formation to determine the impacts of ozone from a single site due to NOx and VOC emissions. In addition, the facility in this project does not directly emit ozone. Therefore, an analysis of nearby ozone emissions impacts was not performed in this project. Finally, we believe that our very strict standards for NOx and VOC from new sources, among the most stringent in the nation, are sufficient safeguard to prevent any single source from contributing significantly to a violation of the ozone NAAQS.

ATTACHMENT M

Rob Simpson Comments and District Responses

Public Comments / District Response

The comments (from Rob Simpson) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Rob Simpson Comments – Emailed Letters Received November 17, 2010

Simpson Comment #1 - Public Notice:

The notice was not given to me in sufficient enough time to prepare adequate comments. The newspaper notice does not provide enough information about the project to the public and was not published in Spanish.

District's Response:

On the contrary, although Mr. Simpson was not on record as being interested in receiving information regarding this specific project, we are always quite interested in providing interested parties an opportunity to provide input, and so we provided a full 30-day period for Mr. Simpson to comment, the same amount of time provided all interested parties on all permitting projects. As for the second comment, please refer to our response to GreenAction's comment #1.

Simpson Comment #2:

The revised PDOC seems to have one purpose, evasion of the Clean Air Act requirements for the Prevention of Significant Deterioration (PSD). The only change in the revised permit is a limitation on annual NOx and CO emissions but the way the permit is worded this limitation is not federally enforceable. Page 9 of the PDOC states that,

> "*The facility has proposed to limit the annual facility wide NOx emissions to 198,840 lb/year. If the annual NOx emissions from these units exceed this value, they will be set equal to the proposed facility wide NOx emission limit.*"

Page 10 of the PDOC states:

> *"The facility has proposed to limit the annual facility wide CO emissions to 197,928 lb/year. If the annual CO emissions from 'these units exceed this value, they will be set equal to the proposed facility wide CO emission limit."*

So essentially there is no change from the original permit and the Avenal Power Project still requires a PSD permit. Issuance of this permit would be a violation of the Clean Air Act and the district and the applicant would be subject to enforcement.

District's Response:

See response to NRDC and CRPE comment #2.

Simpson Comment #3 - The District is the Lead Agency for this Project:

The CEC appears to no longer be the lead agency for the project the district under CEQA, CEC or District rules. The District is now the lead agency since the purpose of the revision to the permit is merely to avoid PSD review and the CEC has no jurisdiction over PSD issues on this project. Thus the district is now the lead agency for review of this project and must conduct a complete EIR prior to issuance of an Authority to Construct for this project.

District's Response:

The District is not the lead agency for this project. Pursuant to California Public Resources Code Section 25500, the CEC "shall have the exclusive power to certify all sites (for power plants over 50 MW) and related facilities in the state". The California Public Resources Code further states that "the issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency".

Simpson Comment #4 - Is an FDOC an ATC?:

- Does the FDOC process comport with the Districts Federal permitting requirements?
- Is it the federal New Source Review (NSR) permit?
- Has the prior FDOC expired for this facility?
- Has the Applicant commenced construction or use of the prior FDOC?

District's Response:

The FDOC complies with Federal non-attainment pollutant permitting requirements, as implemented with the District's EPA-approved non-attainment NSR rule. This rule requires the District to issue a Determination of Compliance, rather than an Authority to Construct because, as noted above, the CEC has the sole licensing authority for large power plants in California. Our NSR rule does not incorporate federal attainment NSR (PSD) requirements. EPA retains the sole authority to issue PSD permits in the San Joaquin Valley.. The prior FDOC is tied to the CEC's license that has been issued, therefore it has not expired. However, the facility has not commenced construction or use of the prior FDOC. The FDOC under which construction is commenced (and only after CEC has approved any related licensing action) will determine the conditions under which the facility must operate.

Simpson Comment #5:

- I contend that the Warren Alquist Act hijacks air districts authority under the Clean Air Act in conflict with Federal law, does the District agree?.
- Does the District agree with the Brief submitted by the South Coast Air District (Exhibit 3) in the Humboldt Superior Court proceeding regarding a power plant permit that I appealed?

District's Response:

The District does not agree with either the "hijack" comment or the South Coast AQMD's brief on the subject. State law provides the CEC with sole permitting authority, but does not allow them to issue a license that violates the District's regulations. The DOC process provides the District ample opportunity to provide the appropriate guidance to the CEC prior to their licensing process. This process does not violate federal permitting requirements in any way. The federal EPA has approved the DOC process as embodied in the language of the District's NSR rule and that approval explicitly acknowledges that the process complies with federal permitting requirements.

Simpson Comment #6:

The District indicated in emails that it did not intend to issue an Authority to Construct for this project. Please provide some indication of how the permit would be enforceable without an Authority to Construct and who could enforce the State and Federal aspects of the permit. The PDOC has extensive references to an ATC.

District's Response:

Thank you for pointing out that we referred to the DOC as the ATC several times in our evaluation. We apologize for that error. The District has removed all references to the issuance of ATC's in the FDOC evaluation.

Pursuant to District Rule 2201, Section 5.8.9, the APCO shall issue a Permit to Operate to any applicant receiving a certificate from the California Energy Commission pursuant to this rule provided that the construction or modification is in compliance with all conditions of the certificate and of the Determination of Compliance, and provided that the Permit to Operate includes the conditions prescribed in Section 5.7. The District will then perform inspections of the facility to determine if it meets all requirements on their PTO.

Simpson Comment #7 - The BACT Analysis for the Permit is Defective:

The district's top down BACT analysis for NOx is defective because it fails to:

- Identify any alternative technologies or work practices which are technologically feasible for reducing NOx emissions, and
- To quantify the collateral impacts from the selection of SCR as the proposed alternative, and
- Identify combustion technologies that are effective is reducing NO_X emissions. (i.e. steam injection, dry low NO_X combustors, and catalytic combustors), and
- Analyze post-combustion controls including selective noncatalytic combustion and EM, and
- Evaluate the risk of an accident from the transport of NH_3, and
- Evaluate NH_3 as a precursor to PM2.5.

District's Response:

The District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The existing Top-Down BACT Analysis did not consider any NO_X emissions control other than the use of SCR to lower the NO_X emissions to 2.0 ppmvd @ 15% O_2, as no more efficient technology has been identified. Pursuant to the District BACT Policy, no analysis is necessary for a project in which the most effective control alternative listed in the BACT Guideline is selected. BACT Guideline 3.4.2 identifies BACT for NO_X as the use of SCR or equal to meet an emission concentration limit of 2.0 ppmvd @ 15% O_2 as the most stringent technologically feasible NO_X requirement. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.

In addition, BACT only covers operational emissions; therefore the risk from accidents during the transport of NH_3 is not evaluated and can not be evaluated under the District's NSR rule.

The evaluation of NH_3 as a precursor to $PM_{2.5}$ was not performed since the facility is not a Major Source for $PM_{2.5}$ emissions. However, it should be noted that the Valley's atmosphere does contain ammonia, largely from the Valley's considerable agricultural operations, and relatively small amounts caused by SCR systems are insignificant and are quite worth the significant NOx emissions reductions generated by the SCR. In addition, the District did analyze the health risk impacts of the NH3 emissions that are resulting from the requirement that SCR be installed, and there is no significant risk. Also see the response to comment #17, below.

Simpson Comment #8 - NO_X Emissions During Startup and Shut Down:

Emissions are greater during startups, shutdowns and combustor tuning periods than they are during steady-state operation, the BACT limits established for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. The discussion of Best Available Control Technologies does not include information on minimizing startup emissions or startup durations. The U.S. Environmental Protection Agency (U.S. EPA) requires that BACT apply not only during normal steady-state operations but also during transient operating periods such as startups. The District should consider conducting, as part of the BACT analysis, a review of combustion turbine and combined cycle system operational controls or design features that can shorten start up and shutdown events and optimize emission control systems.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised.

Simpson Comment #9 - BACT VOC Emission Limit:

The district has selected a VOC emission limit of 1.4 ppmvd @ 15% 02 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% 02 when it is fired with the duct burners. The BAAQMD has recently established a BACT VOC emission limit for large gas turbines for VOC's. BACT is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMBtu, which is equivalent to 1 ppm POC, 1-hr average. Since VOC emissions contribute to ozone formation and the district is in severe non attainment for the 8-hour ozone standard the district should adhere to the lower VOC emission rate or provide a top down BACT evaluation which shows that this rate is not achievable or is not cost effective.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The District Top-Down BACT Analysis did not consider any VOC emissions control other than limiting the VOC emissions to 2.0 ppmvd @ 15% O_2 when the duct burner is fired, and 1.5 ppmvd @ 15% O_2 when the duct burner is not fired.

The applicant proposed VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct *burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in the BACT. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

<u>Simpson Comment #10 - BACT $PM_{2.5}$ / PM_{10} Emission Limit:</u>

The permit proposes to allow the project to emit as much as 11.78 pounds per hour of PM-10 with the project utilizing duct firing. According to BAAQMD the projects listed in the table below all have lower PM emission limits than those proposed for this project. BACT for PM 2.5 for large combined cycle turbines with duct firing is 9 pounds per hour. The district needs to impose this limit in the FDOC.

<u>District's Response:</u>

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. *District BACT Policy, Section IX.D, states that a cost effective analysis is not necessary for a project in which the most effective control alternative is selected. BACT Guideline 3.4.2 identifies BACT for PM_{10} as the use of an air inlet filter, lube oil vent coalescer and natural gas fuel. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed. In addition, it is likely that a PM10 limit of 11.78 lb/hr is substantially the same as a PM2.5 limit of 9.0 lbs/hr, as PM2.5 is a fraction of PM10.*

<u>Simpson Comment #11 - Air Quality Impact Analysis:</u>

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether 'the operation of the proposed equipment will cause or make worse a violation of an air quality standard. For NOx the impact analysis conducted by the district in Attachment G page 2 demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98th percentile of the annual distribution of the daily 1 hour max ppb /ug/m3 for the Visalia site which is 115.72 ug/m3. So the project does in fact violate the new federal NO2 standard and thus cannot be permitted.

<u>District's Response:</u>

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour *max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.*

<u>Simpson Comment #12:</u>

The PDOC uses the PM-10 surrogate approach to analyze the particulate matter impacts from the project. On October 20, 2010, the USEPA issued a final rule providing modeling thresholds for evaluating impacts of PM2.5 emissions under the Prevention of Significant Deterioration (PSD) program and the Non attainment NSR program. The rule establishes Class I and Class II Increment Thresholds and Significant Impact Levels (SILs), and a Significant Monitoring Concentration (SMC) threshold. The project according to the analysis presented on page 54 exceeds both the significant impact levels for the annual PM 2.5 standard and the 24 PM 2.5 hour standard. The FDOC needs to address the compliance of the project with the new rules.

<u>District's Response:</u>

The project does not trigger PSD permitting and the facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, the District is not required to perform modeling to evaluate impacts of $PM_{2.5}$.

<u>Simpson Comment #13 - Federal 1 hour NO2 Standard:</u>

The permit does not present an adequate and complete analysis for the new Federal 1 hour NO2 standard. The district failed to include information on any nearby sources which are required to be modeled with Avenal's emissions. A full impact analysis should be presented in the permit for the public to comment on using the EPA's Guideline on Air Quality Models (40 CFR Part 51 Appendix W).

<u>District's Response:</u>

This project does not trigger a PSD permit and therefore it is not required to follow the guideline on air quality models in 40 CFR Part 51 Appendix W. If it did trigger PSD permitting, the federal EPA would be obligated to perform such modeling, if appropriate.

<u>Simpson Comment #14:</u>

The revised permit should provide the input data that was used to determine compliance with the new NO2 standard. Emission factors and NO2 inventories should be presented for the public to review not just the information that is presented on page 2 Attachment G. The analysis on page 2 Attachment G demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98^{th} percentile of the annual distribution of the daily 1 hour max ppb / ug/m3 for the Visalia site which is 115.72 ug/m3.

District's Response:

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.

Simpson Comment #15:

Modeling for the NO2 standard should indicate whether worst case emissions which would be the start up and shut down emissions for the project were utilized in the modeling for compliance with the standard.

District's Response:

The District performed modeling during the commissioning period and the standard operational period to determine compliance with the NO2 standard. The modeling performed by the District for these periods demonstrated compliance with the NO2 standards.

Simpson Comment #16 - The Proposed Interpollutant Trade Values Violates EPA Guidance and $PM_{2.5}$ NSR Regulations:

Based on an EPA assessment, the preferred trading ratios for SO2 to PM2.5 was set at 40:1.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #17 - Ammonia Emissions:

Other power plant turbines have achieved a 2 ppm NO_X limit with a 5 ppm NH_3 slip limit.

The district must consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The district is not an isolated island.

District's Response:

Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM_{10} formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts $PM_{2.5}$ plan which does not not rely on ammonia reductions to reduce $PM_{2.5}$, but rather relies largely on NO_X reductions.

Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NOx BACT performance levels (2.0 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.

Simpson Comment #18 - Emission Reduction Credits:

ERC's used on the prior PDOC are unavailable for use on the new PDOC.

District's Response:

The ERC listed in the previous FDOC and the ones listed in the new PDOC will only be used for one of the projects. Once they are withdrawn for either project, they will no longer be available to be withdrawn for the remaining project. In addition, the applicant has provided sufficient ERC's of offset the emissions increase in either one of the projects.

Simpson Comment #19:

The PDOC indicates that the closest population center is the residential district of Avenal approximately 6 miles to the southwest. Are there people residing or working closer than that to the project? Could there be sensitive receptors closer to the site?

District's Response:

According to the application submitted by the facility, the nearest resident is 7,700 feet to the Northeast and the nearest business is 3,957 feet to the Northwest. However, our analysis of emissions and risk from those emissions is based on a theoretical long-term exposure at the point of maximum pollutant concentration. Therefore, our conclusion that there will be no significant risk from any emissions from this facility is not dependant on receptor location.

Simpson Comment #20:

It appears that there are residential structures and extensive farm land around the site. Could emissions from the facility affect crops or wildlife?

District's Response:

Such issues are addressed in the CEC's CEQA-equivalent process and are not a part of the District's analysis. However, it should be noted that the District's Health Risk Assessment (HRA) is a multipathway assessment of risk, and would include the affect on public health generated by pollutant deposition on plants and animals that are subsequently ingested by the public.

Simpson Comment #21:

- Has the District conducted and Environmental Justice analysis of the projects effects? Could farm workers be an environmental justice community that suffers a greater impact due to hard physical labor in the vicinity of the project, lack of health care, poverty and additional stressors like chemicals used in farming?
- Can farming activities cause additional air quality impacts that could contribute to a negative cumulative effect?
- Will this facility induce growth?
- Could on site Solar pre-heaters reduce Air quality impacts?
- Can this facility cause an increase of greenhouse gas emissions?
- Are there potential negative localized effects of Greenhouse gases?
- How does this plan comport with AB32?
- How does this plan comport with EXECUTIVE ORDER S-3-05?
- Has the District studied the potential air quality effects of the use of imported LNG?
- The District should study the life cycle effects of fossil fuel extraction and delivery?
- Has the District studied the effects of the facility utilizing water from the California Aqueduct?
- Will the vaporization of this water lead to negative air quality effects by increasing PM or other pollutants in the Air?

- Will the use of this water cause negative air quality effects by the diversion of water that could be utilized for farming or other uses?
- Will the pumping of this water through the Aqueduct, from its source, cause Air quality emissions?
- Is it legal to use Potable water for this Power plant use?
- As water quality changes will these effects change?
- Are there methods of minimizing these potential effects? Dry cooling for instance?

District's Response:

These questions should be directed to the CEQA lead agency for this project (CEC). Since the District is not the lead agency for this project, these comments will not be addressed at this time.

Simpson Comment #22:

How much money does the District receive if this project is approved? Denied?

District's Response:

Whether the project is approved or denied, the District receives application filing fees for all proposed equipment, and hourly engineering fees for the time spent evaluating the project. At this time, we would expect the total will be approximately $5,000. In addition, if the project is approved, the District will receive an annual permit fee to maintain the facility's permits, of approximately $26,000 per year. This latter amount would be the same whether the facility constructs under the conditions of this FDOC and a subsequent CEC approval, or under the existing FDOC which the CEC used in issuing the existing power plant license.

Comments Received from Rob Simpson in Exhibit 4:

The document provided labeled Exhibit 4 is the same document that Mr. Simpson presented as testimony for the CEC Hearings under proceeding 08-AFC-01. This exhibit was discussed at the Pre-Hearing Conference on June 30, 2009. After a review of the document, the CEC Committee overseeing the project concluded that the only information that would be allowed as testimony would be the information included in Exhibit W. A discussion of this can be found in the Pre-Hearing Conference Transcript, available at: http://www.energy.ca.gov/sitingcases/avenal/documents/2009-06-30_TRANSCRIPT.PDF. The District agrees with CEC's conclusion and will respond to the comments presented in Exhibit W. All additional comments in Exhibit 4 are documents pertaining to projects unrelated to this project, and comments that are not applicable to this project.

Simpson Comment #23:

The applicant proposes to offset the projects PM 2.5 emissions on a pound for pound basis with SOx offsets. Proposed interpollutant trading ratios are required to be scientifically justified with a site specific air quality analysis, as required by Rule 2201, Section 4.13.3. The PDOC attempts to establish an interpollutant ratio based on modeling analyses performed in the Districts 2008 PM 2.5 plan.

The EPA has finalized its regulations to implement the New Source Review (NSR) program for fine particulate matter on July 15, 2008. Their recommended ratio of SOx offsets to PM 2.5 offsets is 40 tons of SOx for each ton of PM 2.5. The applicant is proposing a ratio that is 40 times less stringent than EPA has recommended.

In addition the CEC and the air district allow the project to emit 33,521 pounds of SO2 with no mitigation despite the alleged CEC policy to offset all PM2.5 precursors. If one pound of SO2 offsets 1 pound of PM 2.5 the CEC and the Air District are allowing 33,521 pounds of SO2 to remain unmitigated. The new EPA rules on PM 2.5 require a pound for pound offset ratio for PM 2.5 precursors. If the districts assumption that one pound of SOx offsets 1 pound of PM 2.5 as allowed in the interpollutant trade the district is allowing 33,521 pounds of SOx to remain unmitigated creating 33,521 pounds of PM 2.5 in violation of CEQA and EPA NSAR rules for PM 2.5.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #24:

The FDOC allows an ammonia slip of 10 ppm. The 5 ppm ammonia limit in combination with a 2 ppm NO limit has already been required for some CEC licensed facilities. In the alternative the District could perform a site specific analysis that demonstrates that no particulate matter will be formed locally or district wide due to the ammonia slip emissions and require mitigation if the analysis demonstrates that there is significant secondary particulate matter formation from the ammonia emissions from the LGS.

The district must also consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident.

District's Response:

This comment was addressed in the District response to Rob Simpson Comment #17 above.

Comments Received from Rob Simpson in Exhibit 5:

The document labeled Exhibit 5, submitted by Rob Simpson, discusses the California energy landscape. The District does not take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission (CEC).

Attach. 15

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

MAR 2 2 2016

N. Ross Buckenham
ABEC #3 LLC dba Lakeview Dairy Biogas
c/o California Bioenergy, LLC
2828 Routh St, Suite 500
Dallas, TX 75201-1438

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-8637
Project Number: S-1143770

Dear Mr. Buckenham:

Enclosed for your review and comment is the District's analysis of ABEC #3 LLC dba Lakeview Dairy Biogas's application for an Authority to Construct for installation of an anaerobic digester system and two 1,468 bhp digester gas-fired IC engines with selective catalytic reduction (SCR) systems for emissions control at Lakeview Farms dairy, at 17702 Bear Mountain Blvd, Bakersfield, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Ramon Norman of Permit Services at (559) 230-5909.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:rn

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Digester System and Two Digester Gas-Fired IC Engines with SCR

Facility Name:	ABEC #3 LLC dba Lakeview Dairy Biogas	Date:	March 7, 2016
Mailing Address:	ABEC #3 LLC c/o California Bioenergy, LLC 2828 Routh Street, Suite 500 Dallas, TX 75201-1438	Engineer: Lead Engineer:	Ramon Norman Jerry Sandhu
Contact Person:	N. Ross Buckenham - California Bioenergy/ ABEC #3 LLC		
Telephone:	(214) 849-9886	Cell Phone:	(214) 906-9359
E-Mail:	rbuckenham@calbioenergy.com		
Application #(s):	S-8637-1-0, -2-0, and -3-0		
Project #:	S-1143770		
Deemed Complete:	May 14, 2015		

I. Proposal

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kW. The new digester will be constructed in an area of the existing dairy that is currently used for manure drying and storage. Lakeview Farms dairy will send manure from the dairy to the ABEC #3 LLC anaerobic digesters located on the dairy site. The digester system will produce renewable biogas that will be used to fuel the IC engine generator sets.

ABEC #3 LLC dba Lakeview Dairy Biogas and Lakeview Farms dairy, which are separate companies, are undertaking the project as a partnership. ABEC #3 LLC has provided information supporting that the dairy and the ABEC #3 LLC biogas facility will be separately owned and operated. The following is a summary of some of the information provided by the applicant. The proposed digester system at the dairy will be operated and maintained by ABEC #3 LLC. The responsibility of the dairy will be limited to providing the manure feedstock and disposing of the effluent, which the dairy already must do for compliance with water quality regulations. ABEC #3 LLC will not be involved at all in the dairy's primary activity, production of milk. The feedstock and lease agreements specify that ABEC #3 LLC will build, own, and operate the biogas facility and also allows ABEC #3 LLC to make plant and equipment improvements. The proposed digester gas-fired IC engine generator sets that will be constructed on land leased from the dairy site and will be owned, operated, and maintained by ABEC #3 LLC. ABEC #3 LLC will be solely responsible for ensuring that the digester system and digester gas-fired IC engines comply with all applicable air quality regulations. The generator sets will sell all the power generated to the grid and will not provide any power directly to the dairy. Because the dairy and the proposed digester gas power plant at the site will be separately owned and operated and will have different two-digit Standard Industrial Classification (SIC) codes (Industry Group 24: Dairy Farms for the dairy vs. Industry Group 49: Electric, Gas, And Sanitary Services for the IC engine generator sets), pursuant to Section 3.39 of District Rule 2201, the proposed digester system and the digester gas-fired IC engines will not be part of the dairy agricultural stationary source. Therefore, the digester system and digester gas-fired IC engines will be permitted as a separate non-agricultural stationary source (Facility S-8637).

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4701	Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702	Stationary Internal Combustion Engines (11/14/13)
Rule 4801	Sulfur Compounds (12/17/92)

40 CFR Part 60, Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
40 CFR Part 63, Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The ABEC #3 LLC Stationary Source (Facility S-8637) is located on Lakeview Farms dairy at 17702 Bear Mountain Blvd, Bakersfield, CA (Mt. Diablo Meridian T 31S, R 26E, Sec 20 in Kern County). The proposed equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

<u>Anaerobic Digester System</u>

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic decomposition results in the conversion of organic compounds in the substrate into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate Volatile Organic Compounds (VOCs). The gas generated by this process is known as biogas, waste gas, or digester gas. In addition to methane and carbon dioxide, biogas may also contain small amounts of Nitrogen (N_2), Oxygen (O_2), Hydrogen Sulfide (H_2S), and Ammonia (NH_3). Biogas may also include trace amounts of various VOCs that remain from incomplete digestion of the volatile solids in the incoming substrate. Because biogas is mostly composed of methane, the main component of natural gas, the gas produced in the digester can be cleaned to remove H_2S and other impurities and used as fuel.

The proposed anaerobic digester system will be designed to process the manure generated by the cattle at Lakeview Farms dairy. The manure will be flushed from the cow housing areas at the dairy to a mechanical separation system prior to the digester system. This pre-digester mechanical separation system will remove fibrous solids from the manure. After the mechanical separation system, the liquid manure will flow to a sand settling lane that is designed to remove heavy solids by sedimentation. After the separation systems, the liquid manure will gravity flow into the proposed covered lagoon digesters. The liquid effluent from the covered lagoon digesters will be pumped to the existing large storage pond at the dairy from where it can be used to irrigate and fertilize adjacent cropland.

The proposed anaerobic digester system will process the liquid fraction from the dairy manure solid separation system. The anaerobic digester system will consist of an in-ground, covered lagoon anaerobic digester that will be divided into one or more cells. The final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based on borings to locate subsurface sand and groundwater that are required to demonstrate compliance with the requirements of the Regional Water Quality Control Board. The preliminary information submitted by the applicant indicates that the first cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 655 ft long by 262 ft wide at the top, with an average depth of 23 ft, and a side slope (run/rise) of 2.0 and that the second cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 500 ft long by 200 ft wide at the top, with an average depth of 22.75 ft, and a side slope (run/rise) of 2.0. The covered lagoon digester will operate at ambient temperatures; however, the covered lagoon digester may utilize heat from the engines to warm the substrate to promote more efficient anaerobic digestion. An area located east of the existing lagoons at the dairy, which is currently used for drying and storage of solid manure, will be excavated to create the proposed covered lagoon anaerobic digester.

The applicant indicates that the lagoon cell(s) will be covered in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 – Roofs and Covers. The bottom and the walls of the new lagoon cell(s) will be lined with high-density polyethylene (HDPE) membranes and a gas collection system will be installed. The new lagoon cells will be fitted with HDPE covers. The gas collection system will consist of perforated piping under the HDPE covers of the covered lagoons.

The covered lagoon digester will be equipped with an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the digester covers increases the amount of oxygen in the space under the digester covers and in the surface layer of the digester liquid, which facilitates oxidation of sulfides in the digester gas and at the surface of the liquid to elemental sulfur and water. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur. The digester gas will be captured by the covered lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S and for removal of moisture. The gas will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system. When the gas cannot be used in the engines, the digester gas will collect under the lagoon covers. As the gas collects under the lagoon covers, the pressure in the digesters will rise. In rare emergency situations when the gas cannot be combusted in the engines for an extended period, the pressure will cause the relief valves to open and release the digester gas, composed primarily of methane and carbon dioxide, into the atmosphere. As the pressure decreases, the gas relief valves will automatically close and normal operation will proceed.

When operating at full capacity, the digester system is expected to produce an average of 360,000 ft^3 of biogas per day. The applicant has indicated that the biogas produced by the covered lagoon digester will be composed of approximately 60-70% methane and 30-40% carbon dioxide. Because the proposed digester system will be able to store the biogas for extended periods under the digester covers and the proposed engines at the ABEC #3 LLC Stationary Source (Facility S-8637) will have more than sufficient capacity to combust all of the gas generated, no flare is being proposed for the digester installation at this facility.

Covered Lagoon Anaerobic Digester Measurements

The measurements given below for the proposed covered lagoon anaerobic digester cells at the ABEC #3 LLC Stationary Source (Facility S-8637) are based on the preliminary information provided by the applicant. As discussed above, the final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based compliance with the requirements of the Regional Water Quality Control Board.

- 1st Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 655 ft long x 262 ft wide
  - Average Depth: 23 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 2,705,808 ft^3 (~20,239,444 gal)
- 2nd Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 500 ft long x 200 ft wide
  - Average Depth: 22.75 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 1,613,210 ft^3 (~10,612,380 gal)

Digester Gas-Fired IC Engines

The applicant is proposing to install two 1,468 bhp GE Jenbacher model J 320 GS-C82 lean burn digester gas-fired IC engines (or equivalent engines of equal or lesser rating approved by the District, such as 1,412 bhp Caterpillar model A3516A+ IC engines or 1,431 bhp Dresser Rand Guascor model SFGLD 560 IC engines). Each engine will be equipped with an SCR system and will power an electrical generator that will produce up to 1,059 kWe. Digester gas, which consists mostly of methane, the main component of natural gas, will be combusted in the IC engines to produce power. After initial removal of H_2S in the digester system, the digester gas will be piped to the gas conditioning system for polishing to remove H_2S using an iron sponge and/or activated carbon H_2S scrubber or an equivalent H_2S removal system and for removal of moisture. The digester gas will then be piped to the IC engines for use as fuel. The engines will power electrical generators that will produce power to be sold to a utility. Excess heat from the engines will be used in the first covered lagoon anaerobic digester (West

Lagoon Digester) to promote more efficient production of digester gas. The engines will be permitted to operate up to 24 hr/day and 8,760 hr/year.

In addition to the use of digester gas as fuel, the engines will also be permitted to use natural gas as fuel for no more than 96,000 kW-hrs of operation during initial utility interconnect testing in the event that insufficient digester gas is available for the engines at the time that the required utility testing is scheduled. The engines will remain subject to the same emission limits during the limited period that allows the use of natural gas fuel for required utility testing.

V. Equipment Listing

S-8637-1-0: ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

S-8637-2-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

S-8637-3-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

<u>Digester System (S-8637-1-0)</u>

The digester system will be equipped with a pressure-vacuum (PV) relief valves or an emergency venting system. The digester gas will be scrubbed to remove hydrogen sulfide (H_2S) and will be used to fuel engines to generate electricity. Combustion of the digester gas in the engines will convert any VOCs present in the gas into carbon dioxide and water. As stated above, because the digester system will be able to store the gas for extended periods and the engines will have more than enough capacity to combust all of the gas generated, no flare is being proposed for this digester project.

<u>H_2S Removal</u>

As described above, the covered lagoon anaerobic digester will utilize an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the lagoon covers increases the amount of oxygen in the space under the digester covers and the surface layer of the liquid in the covered lagoon digester, which facilitates oxidation of sulfides in the digester gas and in the liquid surface to elemental sulfur and water.

The sulfur dissolves in the liquid in the digester and can be removed from the digester system by deposition and filtration. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur and sulfates that can be removed from the digester system. Use of air injection to remove H_2S from digester gas has been shown to have higher effectiveness in covered lagoon digesters because the large areas under the lagoon covers facilitate contact with the digester gas and lagoon surface, which enables improved oxidation and biological reduction of sulfides. Successful installations of the air injection sulfur removal system have demonstrated significantly reduced operation costs when compared to other methods of sulfur removal.

For final polishing, the digester gas will be sent through an iron sponge H_2S scrubber and/or an activated carbon H_2S scrubber or an equivalent system to remove H_2S from the gas prior to combustion in the proposed engines.

An iron sponge scrubber is comprised of vessel(s) containing iron sponge, which consists of a hydrated form of iron oxide infused onto wood shavings. The wood shavings serve only as a carrier for the iron oxide powder. Iron oxide infused into the wood surface will not wash off or migrate with the gas. As the gas passes through the iron sponge material, the H_2S is removed by the following chemical reaction producing black iron sulfide and water:

$$H_2S + Fe(OH)_2 \longrightarrow FeS + 2H_2O + \text{heat}$$

For the iron sponge to perform effectively, it must be maintained within a defined range of sufficient moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with digester gas. If the iron sponge becomes dry, it can be re-wet and remain effective. The iron sponge reaction is not pressure sensitive.

Specially treated activated carbon can also be used to remove H_2S from gas streams. H_2S will be adsorbed as the gas flows through the activated carbon bed. Activated carbon has a large number of pores, which greatly increase the surface area for adsorption. Contaminants in the gas diffuse into these pores and are retained on the carbon surface due to both chemical and physical forces. Activated carbon used for the removal of H_2S is usually treated with chemical bases to increase the holding capacity for H_2S.

The proposed scrubber will consist of enclosed vessels filled with iron sponge and/or treated activated carbon. The digester gas will flow through the scrubber and then to a dryer and chiller to remove moisture. For continuous operation, there will be a secondary unit that will be brought online at specified times or when monitoring indicates that the primary unit is nearing saturation. Valves can be arranged so either bed can operate while the other is serviced. The useful life of the iron sponge and activated carbon vessels will vary depending on the inlet concentration of H_2S, the flow rate, and the mass in the vessels. Before a scrubber is completely spent, it must be regenerated or replaced. Spent iron sponge or activated carbon vessels will be sent to a regeneration facility or to an appropriate disposal facility.

The proposed scrubber will be capable of reducing H_2S concentrations in the digester gas to 40 ppmv or less. Reducing the H_2S concentration in the gas will minimize SO_X emissions from combustion and will also reduce the maintenance requirements for the engines and will protect catalysts from masking, plugging, and poisoning.

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

The proposed engines will be equipped with:

- Turbocharger
- Aftercooler
- Air/Fuel Ratio or an O_2 Controller
- Lean Burn Technology
- Positive Crankcase Ventilation (PCV) or 90% efficient control device
- Selective Catalytic Reduction (SCR)

The turbocharger reduces NO_X emissions from engines by increasing the efficiency and promoting more complete burning of the fuel.

The aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize engine operation and catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

The PCV system or 90% efficient control device reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, pass through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia. The ammonia is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

VII. General Calculations

A. Assumptions

- ABEC #3 LLC dba Lakeview Dairy Biogas (Facility S-8637) and Lakeview Farms dairy (Facility S-5254) are separate stationary sources at the same site.
- Because of the high moisture content of separated manure solids, PM emissions from the handling of separated solids for the digester system are considered negligible.
- Because the manure for the digester system will be taken from the mechanical separation system at Lakeview Farms dairy and the digested solids and effluent from the digester system will be returned to Lakeview Farms dairy for use, all emissions from the manure

processed in the digester system will be allocated to the liquid manure handling system at Lakeview Farms dairy.

- The proposed digester system will reduce potential VOC emissions from manure generated by the cattle at Lakeview Farms dairy. Manure that is currently stored in uncovered lagoon(s) and pond(s) will instead be placed in covered ponds at the ABEC #3 LLC facility, thereby decreasing volatilization of compounds from the manure. In a digester, most VOCs present will be converted to methane (an exempt compound) and carbon dioxide further reducing the potential for VOC emissions. Because results of dairy digester analyses have indicated very low VOC content (less than 1% by weight), fugitive VOC emissions from the digester system are assumed to be negligible, consistent with District Policy SSP 2015. During operation, the digester gas will be directed to the engines where the gas will be combusted resulting in the oxidation of gaseous hydrocarbons into carbon dioxide and water. Therefore, VOC emissions from the digester system are considered negligible.
- Molar composition of typical digester gas is about 60% methane and 40% carbon dioxide with trace amounts of hydrogen sulfide, VOC, and other compounds.[1]
- Typical Higher Heating Value for Digester Gas: 600 Btu/scf (Per AP-42 (4/00) - notes to Tables Table 3.1-1, Table 3.1-2b, Table 3.1-7, and Table 3.1-8)
- Typical EPA F-factor for Digester Gas: 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (Estimated based on previous digester gas fuel analyses for source tests)
- Average sulfur content of the scrubbed digester gas: 40 ppmv as H_2S (required as BACT; approximately 2.4 grains/100 scf)
- bhp to Btu/hr conversion: 2,545 Btu/hp-hr
- Thermal efficiency of engines: commonly ≈ 33%
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Molecular weights:
  NO_X (as NO_2) = 46 lb/lb-mol   CO = 28 lb/lb-mol   NH3 = 17 lb/lb-mol
  VOC (as CH_4) = 16 lb/lb-mol SO_X (as SO_2) = 64.06 lb/lb-mol
- Each of the engines will be permitted to operate 24 hours/day and 365 days per year.
- There will be no increase in permitted emissions for the limited use of natural gas for required initial utility testing in the event that sufficient digester gas is not available for the engines at the time that the required initial utility testing is scheduled.
- PM2.5 emissions from the digester gas-fired IC engines are assumed to be equal to PM10 emissions.

[1] U.S. EPA AgSTAR (http://www2.epa.gov/agstar), "Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities" (November 2011, http://www2.epa.gov/agstar/agstar-market-opportunities-report); American Biogas Council – Frequent Questions (https://www.americanbiogascouncil.org/biogas_questions.asp); "Anaerobic Digestion Overview", David Schmidt, University of Minnesota Department of Biosystems and Agricultural Engineering (http://www.extension.umn.edu/agriculture/manure-management-and-air-quality/manure-treatment/docs/anaerobic-digestion-overview.pdf); and "Anaerobic Digestion of Animal Wastes: Factors to Consider", ATTRA - National Sustainable Agriculture Information Service (https://attra.ncat.org/attra-pub/summaries/summary.php?pub=307)

Assumptions for Commissioning Period

- The applicant has requested that the ATC permits include a commissioning period to allow testing, adjustment, tuning, and calibration of the engines without the SCR systems installed. The duration of the commissioning period shall consist of no more than 120 hours of operation of each engine without an SCR system installed.
- Engine emissions during the commissioning period will be calculated as uncontrolled based on information provided by the engine supplier.

B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent damage to this equipment. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[2] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

The emission factors for NO_X (1.0 g/bhp-hr), CO (4.85 g/bhp-hr), and VOC (1.0 g/bhp-hr) for the commissioning period are the emission factors provided by the engine supplier for the engines without SCR systems or oxidation catalysts. The emission factors during the commissioning period for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) after initial installation of the SCR system are assumed to be the same emissions factors as during normal operation. SO_X emissions are based on the maximum sulfur content of the dairy digester gas (required as BACT; approximately 2.4 grains/100 scf). PM_{10} emissions on a lb/MMBtu basis are assumed to be similar to natural gas-fueled IC engines. For more conservative PM_{10} emission calculations, the PM emission factor for rich burn natural gas-fueled engines given in EPA's Compilation of Air Pollutant Emission Factors (AP-42) is used because it is higher than the value for lean burn natural gas-fueled engines listed in EPA AP-42. The ammonia emission factor is based on the ammonia slip limit of 10 ppmv NH_3.

[2] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/airtoxics/icengines/docs/20120717riceqaupdate.pdf)

Commissioning Period Emission Factors for Digester Gas-Fired Engines		
Pollutant	g/bhp·hr	Source
NO_X	1.0	Engine Supplier's Information
SO_X	0.04	40 ppmvd in fuel gas; BACT Requirement/Mass Balance equation below
PM_{10}	0.07	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	4.85	Engine Supplier's Information
VOC	1.0	Engine Supplier's Information
NH_3	0.05	10 ppmvd @ 15% O_2 in exhaust; Required/Proposed – See equation below

SO_X – 40 ppmvd H_2S in fuel gas

$$\frac{40\,ft^3\,H_2S}{10^6\,ft^3} \times \frac{32.06\,lb\,S}{lb\text{-}mol\,H_2S} \times \frac{lb\text{-}mole}{379.5\,ft^3} \times \frac{64.06\,lb\,SO_2}{32.06\,lb\,S} \times \frac{ft^3}{600\,Btu} \times \frac{10^6\,Btu}{MMBtu} = 0.0113\,\frac{lb\,SOx}{MMBtu}$$

$$0.0113\,\frac{lb\,SOx}{MMBtu} \times \frac{1\,MMBtu}{10^6\,Btu} \times \frac{Btu_{in}}{0.33\,Btu_{out}} \times \frac{2{,}545\,Btu}{hp\text{-}hr} \times \frac{453.59\,g}{lb} = 0.040\,\frac{g\,SOx}{bhp\text{-}hr}$$

NH_3 – 10 ppmvd @ 15% O_2 in exhaust

$$\frac{10\,ppmv\,NH_3}{10^6} \times \frac{17\,lb\,NH_3}{lb\text{-}mole} \times \frac{lb\text{-}mole}{379.5\,ft^3} \times \frac{9{,}100\,ft^3}{MMBtu} \times \frac{20.9\%\,O_2}{(20.9-15)\%\,O_2} = 0.0144\,\frac{lb\,NH_3}{MMBtu}$$

$$0.0144\,\frac{lb\,NH_3}{MMBtu} \times \frac{1\,MMBtu}{10^6\,Btu} \times \frac{Btu_{in}}{0.33\,Btu_{out}} \times \frac{2{,}545\,Btu}{hp\text{-}hr} \times \frac{453.59\,g}{lb} = 0.05\,\frac{g\,NH_3}{bhp\text{-}hr}$$

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NO_X (0.15 g/bhp-hr), CO (1.75 g/bhp-hr), and VOC (0.10 g/bhp-hr) for the proposed engines during normal operation were proposed by the applicant and are supported by information provided by the engine supplier. The emission factors for NO_X and VOC were required as BACT. The emission factors for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) during normal operation are same as the emission factors presented above for the commissioning period.

Emission Factors for Digester Gas-Fired Engines (Normal Operation)				
Pollutant	g/bhp·hr	lb/MMBtu	ppmvd (@ 15%O_2)	Source
NO_X	0.15	0.0429	11 ppmvd	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
SO_X	0.04	0.0113	40 ppmvd in fuel gas	BACT Requirement/Mass Balance equation above
PM_{10}	0.07	0.01941	--	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	1.75	0.500	210 ppmvd	Proposed by Applicant – See equation on Page 11 below
VOC	0.10	0.0286	21 ppmvd as CH_4	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
NH_3	0.05	0.0144	10 ppmvd	Required/Proposed – See equation above

NOx – 0.15 g/bhp-hr

$$0.15\,\frac{\text{g NOx}}{\text{bhp - hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.0429\,\frac{\text{lb NOx}}{\text{MMBtu}}$$

$$0.0429\,\frac{\text{lb NOx}}{\text{MMBtu}} \times \frac{(20.9 - 15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{46\,\text{lb NOx}} \times \frac{10^6\,\text{ppmv}}{1} = 11\ \text{ppmvd NOx @ 15\% } O_2$$

CO – 1.75 g/bhp-hr

$$1.75\,\frac{\text{g CO}}{\text{bhp - hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.500\,\frac{\text{lb CO}}{\text{MMBtu}}$$

$$0.500\,\frac{\text{lb CO}}{\text{MMBtu}} \times \frac{(20.9 - 15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{28\,\text{lb CO}} \times \frac{10^6\,\text{ppmv}}{1} = 210\ \text{ppmvd CO @ 15\% } O_2$$

VOC – 0.10 g/bhp-hr

$$0.10\,\frac{\text{g VOC}}{\text{bhp - hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.0286\,\frac{\text{lb VOC}}{\text{MMBtu}}$$

$$0.0286\,\frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{(20.9 - 15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{16\,\text{lb VOC}} \times \frac{10^6\,\text{ppmv}}{1} = 21\ \text{ppmvd VOC @ 15\% } O_2$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the digester system and the engines are new emissions units, PE1 = 0 for all affected pollutants.

2. Post Project Potential to Emit (PE2)

Digester System (S-8637-1-0)

As explained above, the digester system will be composed of sealed lagoons that will reduce VOC emissions from the manure and will have negligible fugitive emissions; therefore, VOC emissions from the manure will only be attributed to Lakeview Farms dairy for manure prior to entering the digester system and when returned to the dairy and emissions from the digester system are considered negligible.

Digester Gas-Fired Engines (S-8637-2-0 and -3-0)

Daily PE2 for Each Engine during the Commissioning Period:

Daily PE during the commissioning period for each of the proposed engines is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 During the Commissioning Periods								
NO_X	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) . x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	4.85	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**376.7**	(lb/day)
VOC	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Daily PE2 for Each Engine during Normal Operation after the Commissioning Period:

Daily PE for each of the proposed engines during normal operation after completion of the commissioning periods is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 After Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**11.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**135.9**	(lb/day)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**7.8**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Maximum Annual PE2 for Each Engine During the first Year Including the Commissioning Periods:

As discussed above, each of the proposed engines will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for each engine will calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

NO_X
1,468 bhp x (1.0 g-NO_X/bhp-hr x 120 hr + 0.15 g-NO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **4,583 lb-NO_X**

SO_X
1,468 bhp x (0.04 g-SO_X/bhp-hr x 120 hr + 0.04 g-SO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,134 lb-SO_X**

PM_{10}
1,468 bhp x (0.07 g-PM_{10}/bhp-hr x 120 hr + 0.07 g-PM_{10}/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,985 lb-PM_{10}**

CO
1,468 bhp x (4.85 g-CO/bhp-hr x 120 hr + 1.75 g-CO/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **50,818 lb-CO**

VOC
1,468 bhp x (1.0 g-VOC/bhp-hr x 120 hr + 0.10 g-VOC/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **3,185 lb-VOC**

NH_3
1,468 bhp x (0.05 g-NH_3/bhp-hr x 120 hr + 0.05 g-NH_3/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **1,418 lb-NH_3**

Maximum Total Combined Annual PE2 from Both Engines, Including Commissioning:

The maximum total combined annual PE2 for both the engines, including commissioning emissions, is calculated as follows:

NO_X: 4,583 lb-NO_X/yr-engine x 2 engines = **9,166 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 50,818 lb-CO/yr-engine x 2 engines = **101,636 lb-CO/yr**
VOC: 3,185 lb-VOC/yr-engine x 2 engines = **6,370 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Annual PE2 for Each Engine in years with no Commissioning:

The annual PE2 for each of the engines after completion of the first year of operation when there will not be any commissioning emissions is calculated as follows:

Annual PE2 for Engines S-8637-2-0 &-3-0 with no Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**4,253**	(lb/yr)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,134**	(lb/yr)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,985**	(lb/yr)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**49,614**	(lb/yr)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**2,835**	(lb/yr)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,418**	(lb/yr)

Max Total Combined Annual PE2 from Both Engines in years with no Commissioning:

The maximum total combined annual PE2 for both the engines in years with no commissioning is calculated as follows:

NO_X: 4,253 lb-NO_X/yr-engine x 2 engines = **8,506 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 49,614 lb-CO/yr-engine x 2 engines = **99,228 lb-CO/yr**
VOC: 2,835 lb-VOC/yr-engine x 2 engines = **5,670 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Maximum Daily and Annual PE2 from Calculations Above:

The maximum daily and annual emissions for each pollutant calculated above, including commissioning emissions, are shown in the table below.

Max. Post-Project Potential to Emit (PE2) for S-8637-2-0 &-3-0			
	Max. Daily Emissions for each engine (lb/day)	Max. Annual Emissions for each engine (lb/year)	Max. Total Combined Annual Emissions for both engines (lb/year)
NO_X	77.7	4,583	9,166
SO_X	3.1	1,134	2,268
PM_{10}	5.4	1,985	3,970
CO	376.7	50,818	101,636
VOC	77.7	3,185	6,370
NH_3	3.9	1,418	2,836

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 is equal to zero for all pollutants.

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH_3
ATC S-8637-1-0 (Digester System)	0	0	0	0	0	0
ATC S-8637-2-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
ATC S-8637-3-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
SSPE2	9,166	2,268	3,970	101,636	6,370	2,836

[3] The SSPE2 values listed in this table include the worst case annual emissions during the 120 hours of allowed commissioning time where the engines are allowed to operate uncontrolled for setup and tuning purposes. After the first year, the PE for NO_X, CO, and VOC emissions will go down as the engines will no longer be allowed to operate without controls in place for these pollutants.

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. transportable IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	9,166	2,268	3,970	3,970	101,636	6,370
Major Source Threshold	20,000	140,000	140,000	200,000*	200,000	20,000
Major Source?	No	No	No	No	No	No

* The application for this project was deemed complete before 2/18/2016, which was when the District's PM2.5 Major Source Threshold was lowered to 140,000 lb/year

Note: PM2.5 assumed to be equal to PM10

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

Because this is a new facility, the PE for all regulated NSR pollutants prior to the project is equal to zero.

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since the proposed digester system and engines are new emissions units, BE = PE1 = 0 for all pollutants from each unit.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for PM_{10} (140,000 lb/year), it is not a major source for PM2.5 (200,000 lb/year since the application for the project was deemed complete before 2/18/2016).

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H2S)[4]
- Total reduced sulfur (inlcuding H2S)[4]

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Total PE from New and Modified Units	4.6	3.2	1.1	50.8	2.0	2.0
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix A.

[4] Because the facility is not included in the specific source categories listed in 40 CFR 51.165, for PSD purposes only non-fugitive emissions from the engine exhaust stacks must be addressed for this project. Although the sulfur (primarily H_2S) in the fuel will be converted almost entirely to SO_X during combustion, the maximum possible amount of H_2S and total reduced sulfur compounds from the engine stacks can be calculated by assuming that all sulfur in the fuel is emitted as H_2S. Based on the fuel sulfur limit of 40 ppmv as H_2S, the maximum possible H_2S emission factor for the engines is calculated to be 0.02 g-H_2S/bhp (0.0056 lb-H_2S/MMBtu), resulting in a total combined maximum of < 0.06 tpy H_2S from the exhaust stacks of both engines. This is well below the applicable PSD threshold of 250 tpy.

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the applicant is proposing to install a new digester system with and two new digester gas-fired IC engines.

<u>Digester System (S-8637-1-0)</u>

As explained above, the digester system will consist of sealed lagoon(s) that will reduce VOC emissions from the manure at the dairy and emissions from the digester system are considered negligible. Therefore BACT for new units with PE > 2 lb/day purposes is not required for the digester system.

<u>Digester Gas-Fired Engines (S-8637-2-0 and -3-0)</u>

The proposed engines will each have a PE greater than 2.0 lb/day for NO_X, SO_X, PM_{10}, CO, VOC, and NH_3. Therefore, BACT is triggered for NO_X, SO_X, PM_{10}, and VOC. As part of the BACT requirements, NH_3 slip from the SCR systems will also be limited. The PE for CO from each unit also exceeds 2.0 lb/day; however, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered for relocation of an emissions unit.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore, BACT is not triggered for modification of a unit.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 or Federal Major Modification. Therefore BACT is not triggered for Major Modification purposes.

2. BACT Guideline

S-8637-2-0 & -3-0

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engines. (See Appendix B)

3. Top-Down BACT Analysis

Pursuant to the Top-Down BACT Analysis (See Appendix B), BACT has been satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Fuel sulfur content ≤ 40 ppmv (as H_2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H_2S)
VOC: VOC emissions ≤ 0.10 g/bhp-hr
NH_3: NH_3 slip emissions ≤ 10 ppmv @ 15% O_2

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	9,166	2,268	3,970	101,636	6,370
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements.

The PE2 for the proposed new IC engines is compared to the daily PE Public Notice thresholds in the following table:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	77.7	100 lb/day	No
SO_X	3.1	100 lb/day	No
PM_{10}	5.4	100 lb/day	No
CO	376.7	100 lb/day	**Yes**
VOC	77.7	100 lb/day	No
NH_3	3.9	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	9,166	20,000 lb/year	No
SO_X	0	2,268	54,750 lb/year	No
PM_{10}	0	3,970	29,200 lb/year	No
CO	0	101,636	200,000 lb/year	No
VOC	0	6,370	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for surpassing an offset threshold.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	9,166	0	9,166	20,000 lb/year	No
SO_x	2,268	0	2,268	20,000 lb/year	No
PM_{10}	3,970	0	3,970	20,000 lb/year	No
CO	101,636	0	101,636	20,000 lb/year	**Yes**
VOC	6,370	0	6,370	20,000 lb/year	No
NH_3	2,836	0	2,836	20,000 lb/year	No

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE > 20,000 lbs is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating, this change is not a Title V Significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions from an emissions unit in excess of 100 lb/day and for an SSIPE for CO that exceeds 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (ARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and must be enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions for the Digester System (S-8637-1-0)

As stated above, the digester system will reduce emissions from the manure produced by cattle at Lakeview Farms dairy. The following condition will be placed on the ATC permit to ensure that fugitive emissions from the digester system will be negligible:

- The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
- The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions for the Digester Gas-Fired Engines (S-8637-2-0 & -3-0)

Proposed Rule 2201 (DEL) Conditions for Engines during Both Commissioning and Normal Operation:

- This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]

- During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
- The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
- Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For these digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr) and maximum number of hours allowed for commissioning activities.

- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
- The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Normal Operation:

For the proposed digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC during normal operation are stated in the form of emission factors (g/hp-hr & ppmv), the maximum engine horsepower rating (1,468 bhp), and the maximum operational time of 24 hours per day.

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

E. Compliance Assurance

1. Source Testing

The proposed 1,468 bhp digester gas-fired engines are subject to District Rule 4702 - Internal Combustion Engines. Section 6.3.2.1 of District Rule 4702 requires source testing of NO_X, CO, and VOC emissions at least once every 24 months for a non-agricultural spark-ignited IC engine. The periodic source testing required by District Rule 4702 will ensure compliance with the applicable New Source Review (NSR) requirements NO_X, CO, and VOC. Therefore, source testing for NO_X, CO, and VOC will be required within 90 days of initial start-up and at least once 24 months thereafter. Since the control equipment will include an SCR system, periodic testing of ammonia slip will also be required. In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. The PM_{10} emissions from the engine are not expected to change much over time as long as the quality of the gas used to fuel the engines remains consistent. The facility will be required to periodically monitor the sulfur content of the digester gas fuel, which should ensure that the quality of the digester gas fuel is consistent. Therefore, initial PM_{10} source testing will be required to demonstrate compliance with the PM_{10} emission limit, but ongoing PM_{10} source testing will not be required.

The proposed engines are also subject to 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, no testing requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

The following conditions will be placed on the engine permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]
- Fuel sulfur analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided it to the District upon request. [District Rules 2201 and 4702]
- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

2. Monitoring

As stated above the engines are subject to District Rule 4702. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of NO_X emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. Therefore, quarterly monitoring of NO_X, CO, and O_2 concentrations in accordance with pre-approved alternate monitoring plan "A" within District Policy SSP 1810 will be required. Since the engines will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the engine permits to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]
- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Because of the variable composition of digester gas, additional monitoring of the fuel sulfur content of the digester gas will be required. The following conditions will be placed on the engine permits to ensure compliance:

- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

The following conditions will be listed on the engine permits:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or

volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

4. Reporting

No reporting is required to demonstrate compliance with District Rule 2201.

As stated above, the proposed 1,468 bhp engines are subject to 40 CFR 60, Subpart JJJJ. 40 CFR 60, Subpart JJJJ requires uncertified engines rated 500 bhp or more to submit an initial notification to EPA. As explained above, the District has not been delegated the authority to implement this regulation for non-Major Sources; therefore, this requirement will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

F. Ambient Air Quality Analysis (AAQA)

District Rule 2201 requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Appendix C of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds.

The results of the Criteria Pollutant Modeling conducted for the AAQA are summarized in the following table:

Criteria Pollutant Modeling Results*					
Digester Gas-Fired IC Engines	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_X	Pass[1]	X	X	X	Pass
SO_X	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H2S	Pass	X	X	X	X

* Results were taken from the PSD spreadsheet.

1 The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

2 The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

3 H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4101 Visible Emissions

Rule 4101 states that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity.

Since the IC engines are fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

A Health Risk Assessment (HRA) is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix C), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project. The results of the health risk assessment are summarized in the table below.

RMR Summary			
Categories	**1,468 bhp Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score[1]	107 (each)	214	>1
Acute Hazard Index	0.48 (each)[1]	0.95	0.95
Chronic Hazard Index	0.16 (each)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (each)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix C of this report, the emissions increases for this project was determined to be less than significant.

To ensure compliance with the HRA; the following condition will be listed on the engine permits:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

This condition, along with the engine rating in the equipment description, will ensure that the H_2S emissions from the engine exhaust stack shall not exceed 1.97 lb/hr, as required by the Health Risk Assessment.

Rule 4201 Particulate Matter Concentration

The purpose of this rule is to protect the ambient air quality by establishing a particulate matter emission standard. Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

$$0.07 \quad \frac{g}{hp \cdot hr} \times \frac{1 hp \cdot hr}{2{,}545 Btu} \times \frac{10^6 Btu}{9{,}100 dscf} \times \frac{0.33 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = \quad 0.015 \quad \frac{grain}{dscf}$$

Since 0.015 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4701 Stationary Internal Combustion Engines – Phase I

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion Engines

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SO_X) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0. The proposed new engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engines.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 NO_X, CO, and VOC emission limits pursuant to Table 2;

5.2.2.1.2 SO_X control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and

5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NO_X emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. Pursuant to Section 5.2.2.2.1, engines in the fee payment program shall have actual emissions not greater than the applicable limits in Table 1 during the entire time the engine is part of the fee payment program. Pursuant to Section 5.2.2.2.2, compliance with Section 5.7 and 5.10, pursuant to the deadlines specified in Section 7.5, is also required as part of the fee payment option.

Section 5.2.2.3 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. An operator electing this option shall not be eligible to participate in the fee payment option outlined in Section 5.2.2.2 and Section 5.6.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations
(Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)

Engine Type	NO_X Emission Limit (ppmv @ 15% O_2, dry)	CO Emission Limit (ppmv @ 15% O_2, dry)	VOC Emission Limit (ppmv @ 15% O_2, dry)
1. a. Rich-Burn, Waste Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. c. Rich-Burn, Limited Use	25 ppmv	2,000 ppmv	250 ppmv
1. d. Rich-Burn, Not Listed Above	11 ppmv	2,000 ppmv	250 ppmv
2. a. Lean-Burn, 2-Stroke, Gaseous Fueled, >50 bhp & <100 bhp	75 ppmv	2,000 ppmv	750 ppmv
2. b. Lean-Burn, Limited Use	65 ppmv	2,000 ppmv	750 ppmv
2. c. Lean-Burn Engine used for gas compression	65 ppmv or 93% reduction	2,000 ppmv	750 ppmv
2. d. Waste Gas Fueled	65 ppmv or 90% reduction	2,000 ppmv	750 ppmv
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

The proposed digester gas-fired engines will be operated as a separate stationary source than the dairy farm and the District has determined that the IC engines are a non-agricultural IC engines. The digester gas-fired, engines are waste gas-fired engines and are required to comply with the following emissions limits from Table 2, Row 2.d: 65 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2).

Therefore, the following previously presented condition will be listed on the proposed ATC permits for the engines to ensure compliance:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3.1 requires that the operator of a spark-ignited internal combustion engine rated > 50 bhp that is used exclusively in agricultural operations shall not operate it in such a manner that results in emissions exceeding the limits in Table 3 of Rule 4702 for the appropriate engine type on an engine-by-engine basis.

Section 5.2.3.2 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 3 on an engine-by-engine basis, an operator of a spark-ignited agricultural IC engine may elect to implement an alternative emission control plan pursuant to Section 8.0.

Section 5.2.3.3 requires an operator of an agricultural IC engine in that is subject to the applicable requirements of Table 3 shall not replace such engine with an engine that emits more emissions of NOx, VOC, and CO, on a ppmv basis, (corrected to 15% oxygen on a dry basis) than the engine being replaced.

As stated above, the proposed digester gas-fired engines will be operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the proposed engines.

Section 5.2.4 requires the operator of a certified compression-ignited engine rated >50 bhp shall comply with the following requirements of Sections 5.2.4.1, 5.2.4.2, 5.2.4.3, 5.2.4.3, and 5.2.4.4. The proposed digester gas-fired engines are not compression-ignited engines; therefore, Section 5.2.4 does not apply to the proposed engines.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NO_X emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NO_X emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the digester gas-fired engines comply with the applicable emission limits of Table 2 of District Rule 4702; therefore payment of annual emissions fees for the engines is not required and this section of the Rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or

5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or

5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or

5.7.4 Use California Reformulated Diesel for compression-ignited engines; or

5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or

5.7.6 Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

To satisfy BACT, the average sulfur content of the digester gas fuel for the engine will be limited to 40 ppmv (approximately equal to 2.4 grains sulfur per 100 standard cubic feet). The following condition will be listed on the proposed engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NO_X, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NO_X and CO emission concentrations,

5.8.1.2 Engine exhaust oxygen concentration,

5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the Rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the engine ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engines will be subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the proposed ATC permits for the proposed digester gas-fired engines include an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engines in this project. Therefore, the following condition will be placed on the engine ATC permits to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the permittee shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.8 requires that for each engine, collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, use of a portable NO_X analyzer to take NO_X emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NO_X emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NO_X emissions readings shall be reported to the APCO in a manner approved by the APCO. NO_X emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that requires periodic NO_X, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. In lieu of installing a nonresettable fuel meter, the operator may use an alternative device, method, or technique in determining daily fuel consumption provided that the alternative is approved by the APCO. The operator shall maintain, operate, and calibrate the required fuel meter in accordance with the manufacturer's instructions. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The proposed spark-ignited non-agricultural digester gas-fired engines are subject to the requirements of Section 5.8; therefore this section of the Rule is not applicable.

Section 5.10 specifies SO_X Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The proposed spark-ignited non-agricultural digester gas-fired engines are required to have a District Permit to Operate; therefore this section of the Rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.1.1.2 Engines subject to Section 8.0;
6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for each engine:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of NO_X, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engine is in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2.

The applicant has submitted all the required information for Section 6.1 in the application for the IC engines evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and
6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the ATC permits:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following previously presented condition will be listed on the proposed ATC permits to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and provided to the APCO upon request. The records shall include, but are not limited to, the following:

6.2.3.1 Total hours of operation,
6.2.3.2 The type of fuel used,
6.2.3.3 The purpose for operating the engine,
6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption

The applicant is not claiming an exemption for the proposed engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Section 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.
6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following conditions will be included the ATC permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the

Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NO_X, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NO_X emissions shall also be reported.

The following conditions will be included in the ATC permits to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The proposed engines will be fueled on digester gas; therefore this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engines; therefore this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 SO_X Test Methods
6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.

6.4.6.2 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.

6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.

6.4.6.4 The SO_X emission control system efficiency shall be determined using the following:

% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$

Where:

$C_{SO2,\ inlet}$ = concentration of SO_X (expressed as SO_2) at the inlet side of the SO_X emission control system, in lb/Dscf

$C_{SO2,\ outlet}$ = concentration of SO_X (expressed as SO_2) at the outlet side of the SO_X emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.

6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the proposed ATC permits to ensure compliance:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.5.1.2 Engines subject to Section 8.0;

6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.

6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engines.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. The applicant has proposed the following alternate monitoring program to ensure compliance with Sections 6.5.2 and 6.5.3 of the Rule.

<u>NO_X Emissions:</u>

In order to satisfy the I & M requirements for NO_X emissions, the applicant has proposed to perform the following:

1. Measurement of NOx emissions concentrations with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and the catalyst control system inlet exhaust temperature and NO_X emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

<u>CO and VOC Emissions:</u>

In order to satisfy the I & M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. Measurement of CO emissions concentrations with a portable analyzer at least once every calendar quarter. Generally, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, no additional monitoring for VOC emissions is required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emissions concentration measurements, the applicant is proposing to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure and CO emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance with the I & M requirements for NO_X, CO, and VOC:

- Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]
- Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s)

within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

- The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

The applicant has proposed that the alternate monitoring program will ensure compliance with these two sections of the Rule. Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance:

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control

system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the specifications of the manufacturer or emissions control system supplier. Therefore, the following conditions will be listed on the proposed ATC permits:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Section 6.5.7 requires procedures and a schedule for using a portable NO_X analyzer to take NO_X emission readings pursuant to Section 5.8.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule. The following previously proposed condition will be listed on the proposed ATC permits:

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time.

The applicant has proposed to comply with the I&M plan modification requirements per this section of the Rule. The following condition will be listed on the proposed ATC permits to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The proposed IC engines will be required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NO_X emission requirements of Section 5.2 for a group of engines. Requirements for use of an AECP include: only engines subject to Section 5.2 are eligible for inclusion in an AECP; during any seven consecutive day period, the operator shall operate all engines in the AECP to achieve an actual aggregate NO_X emission level that is ≤ 90% of the NO_X emissions that would be obtained by controlling the engines to comply individually with the NO_X limits in Section 5.2; the operator shall establish a NO_X emission factor limit for each engine; the operator must submit the AECP at least 18 months before compliance with the emission limits in Section 5.2 is required and receive approval from the APCO; the operator must submit and updated or modified AECP for approval by the APCO prior to any modifications; and the operator must maintain records necessary to demonstrate compliance with AECP. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines proposed under this project; therefore this section of the Rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the IC engines under this project is not currently being proposed and, in addition, certification under this section of the Rule would require that the engines or identical units with the same fuel supply and exhaust control systems were operating and could be source tested to demonstrate compliance with the applicable limits; therefore this section of the Rule is not applicable.

Conclusion

As shown above, the proposed non-agricultural, digester gas-fired, lean burn, IC engines are expected to comply with the applicable requirements of Rule 4702 upon initial operation and no further discussion is required.

Rule 4801 Sulfur Compounds

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of SO_X as (SO_2) = (n x R x T) ÷ P
Where:

n = moles SO_X
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R}$

$$0.0113 \quad \frac{lb}{MMBtu} \times \frac{1\,MMBtu}{9{,}100\,scf_{exhaust}} \times \frac{1\,lb \cdot mol}{64\,lb \cdot SO_2} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times 1{,}000{,}000\,ppm = \quad 7.4 \quad \text{ppmv}$$

Since 7.4 ppmv is ≤ 2000 ppmv, the engines are expected to comply with Rule 4801. The following condition will be placed on the engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

This rule incorporates the New Source Performance Standards (NSPS) from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_X, SO_X, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The proposed engines are 1,468 bhp SI ICEs that will be constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engines are subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part. As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for construction of a renewable energy plant at an existing dairy facility. The proposed renewable energy plant will combust dairy digester gas in IC engines to produce electricity. The proposed project will involve diverting manure from existing open basin(s) and pond(s) at the dairy to covered lagoon digester(s), which will result in the capture of much of the methane that is currently released into the atmosphere from the open basins and pond at the dairy. Combustion of the dairy digester gas at the proposed renewable energy plant will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digesters will result in a large net decrease in the global warming potential emitted from the dairy when compared to current levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that, although the project is considered to take place at a separate stationary source for NSR purposes, the activity will occur on previously developed land at an existing dairy facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-8637-1-0, -2-0, and -3-0 subject to the permit conditions on the attached draft ATC in Appendix D.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-8367-1-0	3020-06	Covered Lagoon Digester	$111.00
S-8367-2-0	3020-10-F	1,468 bhp IC engine	$785.00
S-8367-3-0	3020-10-F	1,468 bhp IC engine	$785.00

Appendixes

A: Quarterly Net Emissions Change (QNEC)
B: BACT Analysis for the Proposed Digester Gas-Fired IC Engines
C: Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)
D: Draft ATCs (S-8367-1-0, -2-0, & -3-0)

APPENDIX A
Quarterly Net Emissions Change (QNEC)

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

S-8637-1-0 (Digester System)

PE1 (lb/qtr) S-8637-1-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-1-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

Quarterly NEC [QNEC] S-8637-1-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	0.0	-	0.0	=	0.0
SO_X	0.0	-	0.0	=	0.0
PM_{10}	0.0	-	0.0	=	0.0
CO	0.0	-	0.0	=	0.0
VOC	0.0	-	0.0	=	0.0

S-8637-2-0 & -3-0 (1,468 bhp Digester Gas-Fired, Lean Burn, IC Engines)

PE1 (lb/qtr) S-8637-2-0 & -3-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-2-0 & -3-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	4,583	÷	4 qtr/year	=	1,145.8
SO_X	1,134	÷	4 qtr/year	=	283.5
PM_{10}	1,985	÷	4 qtr/year	=	496.3
CO	50,818	÷	4 qtr/year	=	12,704.5
VOC	3,185	÷	4 qtr/year	=	796.3

Quarterly NEC [QNEC] S-8637-2-0 & -3-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	1,145.8	-	0.0	=	1,145.8
SO_X	283.5	-	0.0	=	283.5
PM_{10}	496.3	-	0.0	=	496.3
CO	12,704.5	-	0.0	=	12,704.5
VOC	796.3	-	0.0	=	796.3

APPENDIX B

BACT Analysis for Digester Gas-Fired IC Engines

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_X	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_X	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)
Ammonia (NH_3) Slip	≤ 10 ppmv @ 15% O_2		

*** For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

3.3.15

Top-Down BACT Analysis for Project S-1143770
Digester Gas-Fired IC Engines

Current District BACT Guideline 3.3.15 applies to the proposed waste gas-fired IC engines. In accordance with the District BACT policy, information from District BACT Guideline 3.3.15 will be utilized for the BACT analysis for the digester gas-fired engines proposed under this project.

I. Proposal and Process Description

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kWe. The covered lagoon digester will utilize an air injection system for biological removal of H_2S from the digester gas. After initial removal of H_2S in the covered lagoon digester, the digester gas will be captured by the covered the lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S by an iron sponge scrubber and/or activated carbon or an equivalent H_2S removal system and for removal of moisture. The cleaned digester gas, which consists mostly of methane, the main component of natural gas, will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system.

II. BACT Applicability

New emissions units – PE > 2.0 lb/day

New Emissions Unit BACT Applicability for S-8637-2-0 & -3-0 After Commissioning				
Pollutant	PE2 for each unit after commissioning (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/yr)	BACT Triggered?
NO_X	11.7	> 2.0	N/A	**Yes**
SO_X	3.1	> 2.0	N/A	**Yes**
PM_{10}	5.4	> 2.0	N/A	**Yes**
CO	135.9	> 2.0 and SSPE2 ≥ 200,000 lb/yr	101,636	No
VOC	7.8	> 2.0	N/A	**Yes**
NH_3	3.9	> 2.0	N/A	**Yes**

* BACT is not required for CO from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

III. Top-Down BACT Analyses for the Digester Gas-Fired Engines

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed digester gas-fired IC engines under this project.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - List all control technologies

District BACT Guideline 3.3.15 lists the following options to reduce NO_X emissions from waste gas-fired IC engines:

1) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)
2) Fuel Cell (≤ 0.05 lb/MW-hr) (Alternate Basic Equipment)
3) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
4) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

<u>Description of Control Technologies</u>

1) NO_X emissions ≤ 0.15 g/bhp-hr (9-11 ppmv NO_X @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

2) Fuel Cell (≤ 0.05 lb- NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found biogas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

3) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_X emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for biogas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, biogas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller biogas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 biogas-fired microturbines operating in California as of the year 2006.[5] Microturbines generally have electrical efficiencies

[5] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)

of 25-30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30-33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_X emissions of 9-15 ppmv @ 15% O_2. However, several emission tests performed on biogas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[6], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 4) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

b. Step 2 - Eliminate technologically infeasible options

Option 3 - Gas Turbine (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

[6] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[7] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[8] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

The proposed project would require gas turbines rated 1,059 kW each, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
2) Digester gas-fueled microturbines (Alternate Basic Equipment)
3) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engines are non-agricultural IC engines. The lean burn, digester gas-fired, engines are subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.d: 65 ppmvd NO_X (or 90% reduction), 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed digester engines are also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a more stringent VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engines will be based on the emission limits contained in these applicable regulations.

<u>Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)</u>

Because fuel cells have reduced NO_X and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis demonstrates that replacement of the proposed engines with a fuel cell is not cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: $127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[9] *in February 2016*)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [8]

<u>Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 24 hr/day x 1 engine*)
- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

[9] See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in the engines, there will be no increase in operating costs related to cleaning the digester gas for use in IC engines.
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

Assumptions for Fuel Cell System

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace each proposed engine: 1,500 kW (estimated based on 271.71 MMBtu/day and 45% efficiency)
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: $4,550/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at: http://www.wbdg.org/resources/fuelcell.php) states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".*)
- Additional capital investment for biogas conditioning and cleanup for fuel cells: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: $5,113/kW

- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: \$0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for biogas conditioning and cleanup for large fuel cells: \$0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: \$0.19/kW-hr
- Fuel Cell NO_X emissions: 0.01 - 0.02 lb/MW-hr *(Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-NO_X/MW-hr but measured emissions from fuel cells are generally much lower)*
- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level of 0.02 lb-VOC/MW-hr and emission tests on fuel cells)
- Unlike the proposed engines, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

<u>Capital Cost</u>

The estimated increased incremental capital cost for replacement of the proposed engines with fuel cells is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a fuel cell power plant is calculated as follows:

(1,500 kW x \$5,113/kW) - (1,059 kW x \$2,139/kW) = \$5,404,299

<u>Annualized Capital Cost</u>

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

A = $[P \times i(I+1)^n]/[(I+1)^n-1]$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

A = $[\$5,404,299 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$
= **$879,525/year**

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

Fuel Cells (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 1,493 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 13,076,159 kW-hr /year

Cost Decrease from Increased Revenue for Power Generation from Replacing each Proposed 1,059 kW Engine with a Fuel Cell
(9,276,840 kW-hr/yr - 13,076,159 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = -$485,249/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 IC kW Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Fuel Cells (Alternate Equipment)
13,076,159 kW-hr/yr x $0.19/kW-hr = $2,484,470/year

Annual Costs of Increased Maintenance
$2,484,470/yr - $185,537/yr = $2,298,933/year

Total Increased Annual Costs for Fuel Cell as an Alternative to Each Proposed Engine

$879,525/year + (-$485,249/year) + $2,298,933/year = **$2,693,209/year**

Emission Reductions:

NO_X and VOC Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b. The District Standard Emissions for VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2) and 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment: 0.01 lb-NO_X/MW-hr and 0.02 lb-VOC/MW-hr as CH_4

Emission Reductions:

Each Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 0.01 lb-NO_X/MW-hr)
(99,175.4 MMBtu/yr x 0.2540 lb-NO_X/MMBtu) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.01 lb-NO_X/MW)
= 25,060 lb-NO_X/year (12.53 ton-NO_X/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)
(1,468 bhp/engine x 8,760 hr/yr x 1 engine x 1.0 g-VOC/bhp-hr x 1 lb/453.59 g) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW)
= 28,089 lb-VOC/year (14.04 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO_X and VOC Reductions based on District Standard Emission Reductions

(12.53 ton-NO_X/year x $24,500/ton-$NO_X$) + (14.04 ton-VOC/year x $17,500/ton-VOC)
= **$552,685/year**

As shown above, the annualized capital cost of this alternate option exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_X and VOC emission reductions. Therefore, this option is not cost effective and is being removed from consideration.

Option 2 - Microturbines (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

The cost analysis below demonstrates that the NO_X emission reductions achieved by replacement of the proposed engines with microturbines would not be cost effective based on the District's Revised BACT Cost Effectiveness Thresholds (May 14, 2008).

In addition, it should be noted that large lean burn IC engines generally have higher overall efficiencies than microturbines. The difference in efficiency between engines and microturbines will minimize and possibly eliminate any overall differences in NO_X emissions between these options. For example, information from a Capstone Turbine Corporation specification sheet indicates that the guaranteed NO_X emissions rate of 9 ppmvd @ 15% O_2 for their 1,000 kW renewable gas fuel microturbine package is equivalent to 0.14 g-NO_X/hp-hr.[10] This level is not significantly different than the current BACT requirement for waste gas-fired engines of 0.15 g-NO_X/bhp-hr.

The following discussion demonstrates how the difference the efficiency of engines and microturbines can affect the emission rate. NO_X emissions from the engines will be limited to no more than 0.15 g/bhp-hr (approximately 11 ppmv NO_X @ 15% O_2). Microturbine suppliers will generally guarantee NO_X emissions ≤ 9 ppmv @ 15% O_2 For digester gas-fired microturbines. The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11] (March 2015), Table 2-2: Gas Spark Ignition Engine CHP - Typical Performance Parameters, lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12] (October 5, 2015), Page A-28 indicates that "Typical observed efficiencies on IC engines deployed in the SGIP are 27% for electrical conversion (HHV)..." Therefore, the expected HHV electrical efficiency of each of the proposed 1,059 kW engines is between 27-36.8%.

The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11], Table 5-2: Gas Spark Ignition Engine CHP - Microturbine Cost and Performance Characteristics, lists HHV electrical efficiencies of 26-28% for microturbine systems rated at least 200 kW. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12], Table A-15: Microturbine Electrical Conversion Efficiency, lists a HHV electrical efficiencies of 21% for microturbines based on SGIP metered data. Therefore, the expected HHV electrical efficiency of large microturbines is between 21-28%.

The maximum expected NO_X emission factor for the proposed engine-generator sets is approximately 0.47 lb/MW-hr (based on 0.15 g/bhp-hr and 95% generator efficiency). Based on 9 ppmv NO_X @ 15% O2 and the expected range of microturbine electrical conversion efficiency given above, the NO_X emission factor from large digester gas-

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[10] See: http://www.adigo.no/wordpress/wp-content/uploads/2015/02/CR1000-teknisk-spesifikasjon-engelsk.pdf. Note that because of lower efficiencies for smaller microturbines, the guaranteed emission rate of 9 ppmvd NO_X @ 15% O_2 from smaller units will actually be higher than 0.15 g-NO_X/bhp-hr

[11] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies

[12] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

fueled microturbines is expected to range from 0.43 – 0.57 lb/MW-hr. Because, the maximum NO_X emission factor for the proposed engine-generator sets falls within this range, the options could be considered equivalent.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and microturbines will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[11] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and microturbines, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [12]
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines or microturbines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in both engines and microturbines and the same amount of total digester gas will be available for either option, there will be no difference in operating costs related to cleaning the digester gas for use in IC engines or microturbines.
- Price for electricity: $127.72/MW-hr (based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)[9] in February 2016)

Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 24 hr/day x 1 engine*)

- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu

<u>Assumptions for Microturbines</u>

- Net HHV electrical efficiency for a 950 kW net (1,000 kW nominal capacity) microturbine package: 24.5% (*conservative estimate, SGIP metered data indicates an efficiency of 21%*)
- Estimated Size of microturbine system needed to replace each engine: 950 kW net (1,000 kW nominal capacity)
- Estimated Purchase and Installation Cost for 950 kW net (1,000 kW nominal capacity) microturbine package: $2,500/kW (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- Estimated additional capital investment for biogas conditioning and cleanup for microturbines: $744/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled microturbine system rated 950 kW net (1,000 kW nominal capacity): $3,244/kW
- Typical operation costs for a 950 kW net (1,000 kW nominal capacity) microturbine package: $0.012/kW-hr (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- NO_X Emissions for Digester gas-fueled microturbines: ≤ 9 ppmv NO_X @ 15% O_2 (~ 0.0352 lb-NOx/MMBtu)

Capital Cost

The estimated increased incremental capital cost for replacement of each the proposed engines with microturbines is calculated based on the difference in cost of a microturbine system and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a microturbine system is calculated as follows:

(950 kW x $3,244/kW) - (1,059 kW x $2,139/kW) = $816,599

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$816{,}599 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$132{,}898/year}$$

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

950 kW (net) Microturbine Package (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 813 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 7,119,242 kW-hr /year

Cost of Decreased Revenue from Power Generation from Replacing each Proposed 1,059 kW Engine with Microturbines
(9,276,840 kW-hr/yr - 7,119,242 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = $275,568/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 kW IC Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Microturbines (Alternate Equipment)
7,119,242 kW-hr/yr x $0.012/kW-hr = $85,431/year

Cost from Annual Decrease in Maintenance Costs
$85,431/yr - $185,537/yr = -$100,106/year

Total Increased Annual Costs for Microturbines as an Alternative to Each Proposed Engine

$132,898/year + $275,568/year + (-$100,106/year) = **$308,360/year**

Emission Reductions:

NO_X Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2)

Emissions from Microturbines as Alternative Equipment: 0.0352 lb-NO_X/MMBtu (9 ppmv NO_X @ 15% O_2)

Emission Reductions for Each Proposed Engine Compared to Microturbines based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 9 ppmv @ 15% O_2)
99,175.4 MMBtu/yr x (0.2540 lb-NO_X/MMBtu – 0.0352 lb-NO_X/MMBtu)
= 21,700 lb-NO_X/year (10.85 ton-NO_X/year)

Cost of NO_X Emission Reductions

Cost of reductions = ($308,360/year)/[(21,700 lb-NO_X/year)(1 ton/2000 lb)]
= **$28,420/ton of NO_X reduced**

As shown above, the cost of the NO_X emission reductions for replacing each of the proposed engines with microturbines exceeds the $24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost effective and is being removed from consideration.

Option 3: NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

This option is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engines must be satisfied with the following: NO_X: NO_X emissions to ≤ 0.15 g/bhp-hr

The applicant has proposed to use SCR systems for the digester gas-fired lean burn IC engines to reduce NO_X emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. BACT Analysis for SO_X Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce SO_X emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_X emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

3. **BACT Analysis for PM_{10} Emissions:**

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engines. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and CO_2 (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engines:

1) Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

4. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engines is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed IC engines with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

5. BACT Analysis for NH_3 Slip Emissions:

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%. Ammonia slip is the result of unreacted ammonia exiting the SCR system.

a. Step 1 - Identify all control technologies

The District has not established a cost effectiveness threshold for ammonia. Therefore, only options that are determined to be Achieved-in-Practice controls will be considered for ammonia in this analysis.

District BACT Guideline 3.3.15 lists an ammonia slip emission limit of 10 ppmvd @ 15% O_2 as an Achieved in Practice BACT requirement for waste gas-fired IC engines.

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved in practice and has been proposed by the applicant. Additionally, as stated above, a cost effectiveness threshold for ammonia has not been established by the District. Therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for NH_3 slip emissions from the proposed engines is NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. The applicant has proposed IC engines with NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. Therefore, the BACT requirements for NH_3 slip are satisfied.

APPENDIX C

Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)

San Joaquin Valley Air Pollution Control District
REVISED Risk Management Review

To:	Ramon Norman – Permit Services
From:	Yu Vu – Technical Services
Date:	October 22, 2015
Facility Name:	ABEC #3 dba Lakeview Dairy Biogas
Location:	17702 Bear Mountain Blvd, Bakersfield, CA 93311 at Lakeview Dairy (S-5254)
Application #(s):	S-8637-2-0, 3-0
Project #:	S-1143770

A. RMR SUMMARY

RMR Summary			
Categories	**1,468 BHP Bio Gas Engines (Unit 2-0 & 3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	107 (ea.)	214	>1
Acute Hazard Index	0.48 (ea.)[1]	0.95	0.95
Chronic Hazard Index	0.16 (ea.)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (ea.)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Unit # 2-0, 3-0

1) The H_2S emissions from the engine shall not exceed 1.97 lbs/hr. as determined by source testing. [District Rule 2201]

B. RMR REPORT

I. Project Description

Technical Services received a request on October 7, 2015, to perform a revised Risk Management Review for a proposed installation of two 1,468 BHP Dairy Bio gas-fired full time IC engines. Per the project engineer, the following changes to the project were made in this revision:

1) An increase in each engine's rating from 1,412 bhp to 1,468 bhp.
2) An increase in digester gas consumption of each engine from 16,303 scf/hr and 142,812,528 scf/yr to 16,327 scf/hr and 143,024,520 scf/yr.
3) A change in the stack parameters, resulting in the stack exit velocity of each engine increasing from 19.766 m/s to 23.636 m/s.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using District approved Dairy Bio Gas emission factors for internal combustion were input into the HEARTs database. The AERMOD model was used, with the parameters outlined below and meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 2-0, 3-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	9.144	**Closest Receptor (m)**	Various
Stack Diameter. (m)	0.4572	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	23.636	**Max Hours per Year**	8,760
Stack Exit Temp. (°K)	699.817	**Fuel Type**	Dairy Bio Gas
BHP	1,468		

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The emission rates used for criteria pollutant modeling were:

Pollutant	lb/hr	lb/yr
CO	15.6966	50,818
NO_x	3.2364	4,582.7
SO_x	0.1295	1,134.0
PM_{10}	0.2265	1,984.6
H_2S	6.0834	N/A

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Bio-Gas Engine	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H_2S	Pass[3]	X	X	X	X

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[3]H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Toxic emissions summary
D. Prioritization score
E. Facility Summary

APPENDIX D
Draft ATCs
(S-8637-1-0, -2-0, & -3-0)

FOR PROJECT FILE
Emissions Profiles

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-8637-1-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

CONDITIONS

1. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
4. The digester system cover(s) shall be designed and installed in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 - Roofs and Covers. [District Rule 2201]
5. The digester system shall be designed to allow gas generated during summer conditions to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
6. The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
7. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services

S-8637-1-0 : Mar 16 2016 1:06PM – NORMANR : Joint Inspection NOT Required

8. {3658} This permit does not authorize the violation of any conditions established for this facility in the Conditional Use Permit (CUP), Special Use Permit (SUP), Site Approval, Site Plan Review (SPR), or other approval documents issued by a local, state, or federal agency. [Public Resources Code 21000-21177: California Environmental Quality Act]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-2-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services
S-8637-2-0 : Mar 16 2016 1:06PM – NORMANR Joint Inspection NOT Required

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

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CONDITIONS CONTINUE ON NEXT PAGE

38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services
S-8637-3-0 Mar 16 2016 1:06PM – NORMANR : Joint Inspection NOT Required

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

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CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

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38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

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49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

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