Cap-and-Trade Regulation
Post-2020 Allocation to Electrical Distribution Utilities
Informal Staff Proposal

Together, Assembly Bill 32, Senate Bill 32, and Assembly Bill 197 set an ambitious goal for reducing greenhouse gas emissions to 40 percent below 1990 levels by 2030 and provide guidance for how those reductions are achieved. To meet these objectives, the State is developing a 2030 Target Scoping Plan to chart the path to achieve the 2030 limit. Comments received on the 2030 Target Scoping Plan and Cap-and-Trade Regulation (Regulation) rulemaking materials will be considered as staff prepares a final regulation for Board consideration in 2017.

Air Resources Board staff is considering two new options for post-2020 allocation to electrical distribution utilities (EDU) under the Regulation. These two options use methods that are similar to the method used to calculate 2013-2020 EDU allocations, but with some important differences. Consistent with staff's proposal outlined in the 2016 Initial Statement of Reasons[1] to the proposed amendments to the Regulation, in both options under consideration, allocation would be based on Cap-and-Trade Program (Program) cost burden. Cost burden would be calculated by estimating emissions for each year from 2021-2030 associated with generation from natural gas and coal resources listed in 2015 S-2 resource plans submitted to the California Energy Commission (CEC), as explained in greater detail below. Generation from natural gas resources is calculated by subtracting generation from solid fuel and zero-emission resources from total generation to meet load. Zero-emission resources include large hydroelectric and nuclear power, and also include power from facilities eligible under the Renewables Portfolio Standard (RPS), with the assumption that each EDU adds RPS-eligible power that increases from the mandated 33 percent in 2020 to the mandated 50 percent in 2030. Both options include subtracting from an EDU's allocation an amount equivalent to the emissions resulting from power that serves industrial covered entities that are customers of each EDU. The options differ only in that the first option assumes changes in load based on the CEC's 2015 demand forecast, while the second option keeps loads fixed at the load estimated for 2020.

These options differ from the concept initially discussed at a March 29, 2016 public workshop[2] and outlined in the 2016 Initial Statement of Reasons and reflect staff consideration of stakeholder comments and meetings with the Joint Utilities Group and other stakeholders. Staff previously considered allocating to individual EDUs based on calculated cost burden for 2020 and, for each year after 2020, reducing the allocation by multiplying the 2020 cost burden by the cap adjustment factor. This allocation would also account for post-2020 coal plant retirements. Staff had proposed ending the RPS adjustment[3] after 2020 and instead increasing allocations by assuming a requirement of only 28 percent instead of 33 percent RPS power to account for a portion of the RPS Category 2 power that is not directly delivered to California. In response to stakeholder comments, staff now proposes to continue the RPS adjustment post-2020 in its current

[1] https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf
[2] Materials from this workshop are available at https://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm.
[3] Section 95852(b)(4) of the Regulation

form, consistent with the rationale put forth in the 2011 Final Statement of Reasons (FSOR),[4] and to not provide any additional post-2020 allocation to account for investments in out-of-State RPS power that is not imported into California.

This informal staff proposal provides post-2020 EDU allocation amounts for stakeholder review and feedback to inform formal 15-day regulatory amendments.

Proposed Options for Post-2020 EDU Allocation

Staff proposes to allocate allowances to each EDU equal to the cost burden for each year from 2021-2030. Cost burden is the anticipated incremental cost of power to serve load due to the requirement to surrender compliance instruments in the Cap-and-Trade Program. Cost burden is calculated using load data from CEC's 2015 demand forecast and expected generation data from resources in the 2015 S-2 forms,[5] assuming that natural gas provides all generation needed to serve load not met with solid fuel and zero-emission power.

In both options, staff proposes to calculate natural gas power by subtracting generation from solid fuel, large hydro, nuclear, and RPS-eligible facilities from total generation needed to meet load. Power provided under contract with the Intermountain Power Project (IPP) coal plant would be assumed to be replaced with natural gas power for the six EDUs with IPP shares when the contracts end in June 2027.[6] A similar reduction would be made for PacifiCorp based on planned coal plant retirements in PacifiCorp's 2015 integrated resource plan.[7] It would be assumed that the amount of RPS zero-emission power is determined by RPS requirements. Each EDU is assumed to meet RPS targets based on a linear increase from 33 percent of load in 2020 to 50 percent in 2030. Emissions would be calculated using a single emission factor for natural gas (0.4354 metric tons of carbon dioxide equivalent ($MTCO_2e$) per megawatt-hour (MWh)) and different emission factors for solid fuels depending on the generator. Load served by natural gas is assumed to never drop below 5 percent of total load to account for the balancing that is necessary for renewable resources.

The calculated cost burden for each EDU with industrial covered entities would be reduced to account for emissions associated with electricity purchased by these entities.[8] These emissions for each EDU would be calculated as the product of the following factors:

a. Projected annual electricity consumption (MWh) from industrial covered entities served by that EDU = average baseline industrial covered entity

[4] https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf

[5] For EDUs that do not submit S-2s, staff estimates resources using data from integrated resource plans or other data provided by the EDUs.

[6] Pre-2021 retirements of coal would already be accounted for in the S-2 used to calculate cost burden for 2021-2030.

[7] Available at http://www.pacificorp.com/es/irp.html.

[8] 2016 Initial Statement of Reasons. See page 42 for the explanation of the change to EDU allocations, and page 33 for the discussion of including purchased electricity in determining benchmarks for allocation to industrial covered entities.

electricity consumption[9] (MWh) * cap adjustment factor for each year from 2021 to 2030 year; and

b. Annual EDU-specific emission factor ($MTCO_2e$/MWh) = annual EDU cost burden ($MTCO_2e$) / annual EDU load (MWh).

Allocation to industrial covered entities would be done through direct allocation to industrial entities, and the emissions would be included in calculated industry-specific benchmarks.

The only differences between options 1 and 2 concern load, as outlined in Table 1. Option 1 assumes that EDUs' loads change as projected in the 2015 CEC Demand Forecast, which estimates loads through 2026.[10] For 2027-2030, loads would be assumed to change at the average rate calculated for 2014-2026. Under option 2, loads would be fixed at 2020 levels.

Staff continues to assess the potential for adjusting allocation amounts for emissions that result from electrification of transportation. Staff will continue to coordinate with energy agencies and stakeholders to develop a methodology to allocate for this purpose.

Differences from the 2013-2020 EDU Allocation Methodology

- There is no top-down component based on an electricity sector-wide allocation with a percentage of the sector amount for each EDU. Proposed post-2020 methodologies apply to each EDU individually. This will make each EDU's annual allocation more transparent and will simplify changes in allocation when load is sold among EDUs.
- Post-2020 EDU allocation would not include energy efficiency or early action credits because early action has already been recognized, and because energy efficiency and RPS requirements are now essentially the same for publicly-owned utilities and investor-owned utilities.
- The calculated cost burden for each EDU with industrial covered entity customers would be reduced to account for emissions associated with electricity purchased by these entities. Allocation to industrial covered entities would be done through direct allocation to industrial entities, and the emissions would be included in calculated industry-specific benchmarks.
- The proposed calculation of the 2020 cost burden would not account for zero-emission power priced at market, as was done previously for qualifying facility (QF) renewable power.[11]

[9] Calculated as [(2013 industrial covered entity MWh / 2013 cap adjustment factor) + (2014 industrial covered entity MWh / 2014 cap adjustment factor)] / 2.

[10] Form 1.5a–Statewide California Energy Demand Revised/Final Forecast, 2016-2026, Mid Demand Baseline Case, Mid AAEE Savings, Net Energy for Load by Agency and Balancing Authority (GWh). This form provides load estimates for selected utilities and for regions. If specific load estimates for an EDU are not provided, staff would assume loads would change at the average 2014-2026 rate for the region in which the EDU is located.

[11] The total amount of renewable QF power is projected to decline from 3,121 gigawatt-hours (GWh) in 2013 to 251 GWh in 2020 and 101 GWh in 2024. (Source: data from CEC 2015 S-2s, available at: http://www.energy.ca.gov/almanac/electricity_data/s-2_supply_forms_2015/.)

- In option 2, each EDU's load would be assumed to be maintained at the 2020 level, reflecting the CEC's estimate that overall State load will stay nearly flat, decreasing at an annual rate of 0.21 percent.

RPS Adjustment
As discussed in the December 14, 2015 workshop, issues with RPS adjustment reporting were discovered through staff's quality control efforts. The RPS adjustment was originally included in the Regulation to recognize investments in out-of-State RPS-eligible power that is not directly delivered to California. This RPS adjustment is a voluntary option, and it is only applicable when the importer purchases both electricity and renewable energy credits (REC) together and can demonstrate that the electricity was not delivered to California.

The 2016 Initial Statement of Reasons explained why staff proposed to eliminate the RPS adjustment after 2020. Instead of keeping the RPS adjustment, staff proposed to provide each EDU with post-2020 allowance allocation that accounts for a portion of RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California. This allowance allocation was intended to serve the same purpose as the original RPS adjustment, but to alleviate the reporting and verification difficulties and the potential for double counting of zero-emission electricity.

Based in part on comments submitted during the 45-day comment period and at the Board hearing, staff's new proposed allocation methods do not include allocation for higher emitting electricity generation that replaces RPS electricity that is not directly delivered. Instead, staff proposes to continue the RPS adjustment after 2020 with the existing reporting and verification requirements pursuant to the Mandatory Reporting Regulation and as outlined in the 2011 FSOR, and to not provide any additional post-2020 allocation as a substitute for the RPS adjustment since it will remain in effect.[12]

[12] Available at https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/rps-adj-guidance.pdf.

Table 1. Post-2020 EDU allocation proposals. In the interest of brevity, only the 2021 and 2030 allocation amounts are shown for each EDU. Annual allocations would be proposed in 15-day changes to the Regulation.

	2021		2030		Industrial Covered Entities	
Electrical Distribution Utility	**Method 1: Change Load, RPS 33-50%**	**Method 2: Fixed Load, RPS 33-50%**	**Method 1: Change Load, RPS 33-50%**	**Method 2: Fixed Load, RPS 33-50%**	**2021 Adjustment***	**Number of Entities**
Alameda Municipal Power	67,659	68,216	27,724	27,800	-	-
Anza Electric Cooperative, Inc.	29,441	29,410	15,988	15,782	-	-
Azusa Light and Water	66,684	66,372	31,490	29,985	-	-
Bear Valley Electric Service (BVES)	41,162	41,162	19,504	19,504	-	-
Biggs Municipal Utilities	2,273	2,274	780	748	-	-
Burbank Water and Power	504,579	502,924	139,557	133,598	-	-
City and County of San Francisco, Public Utilities Commission	23,910	23,764	15,620	14,863	-	-
City of Anaheim	1,278,736	1,277,356	334,385	323,052	-	-
City of Banning	33,319	33,152	15,182	14,378	-	-
City of Cerritos	26,012	25,906	12,788	12,275	-	-
City of Colton	96,448	96,017	46,208	44,129	-	-
City of Corona Dept. of Water & Power	39,497	39,320	18,913	18,061	-	-
City of Industry	12,808	12,756	6,297	6,044	-	-
City of Lompoc	31,370	31,318	14,224	13,749	-	-
City of Needles	4,142	4,073	820	787	-	-
City of Palo Alto	136,874	136,090	45,364	43,470	-	-
City of Riverside	934,707	933,327	299,196	288,173	-	-
City of Shasta Lake - Electric	57,384	56,832	29,860	26,929	-	-
City of Ukiah	26,093	25,986	11,792	11,279	-	-
City of Vernon	267,007	266,399	131,681	125,683	*	2

* This amount is included in (subtracted from) the amount listed in the column "2021: Method 1: Change Load, RPS 33-50%." An industrial covered entity amount was also subtracted from the 2030 amount based on the calculation methodology outlined in the text. 2021 industrial covered entity adjustments are not shown for EDUs with fewer than 5 industrial covered entities to keep confidential electricity demand data for those entities.

	2021		2030		Industrial Covered Entities	
Electrical Distribution Utility	**Method 1: Change Load, RPS 33-50%**	**Method 2: Fixed Load, RPS 33-50%**	**Method 1: Change Load, RPS 33-50%**	**Method 2: Fixed Load, RPS 33-50%**	**2021 Adjustment***	**Number of Entities**
Eastside Power Authority	3,943	3,904	1,205	1,020	-	-
Glendale Water & Power	383,517	381,862	126,963	121,049	-	-
Gridley Electric Utility	5,416	5,389	1,922	1,816	-	-
Healdsburg Electric Dept.	18,410	18,272	8,354	7,850	-	-
Imperial Irrigation District (IID)	1,017,285	999,405	547,970	460,025	*	3
Kirkwood Meadows PUD	1,850	1,850	877	877	-	-
Lassen Municipal Utility District	31,936	31,763	14,592	13,755	-	-
Liberty Utilities (CalPeco Electric) LLC	165,604	164,128	83,566	77,769	-	-
Lodi Electric Utility	99,984	99,501	46,442	43,217	-	-
Los Angeles Department of Water & Power (LADWP)	8,341,673	8,309,671	2,140,872	2,070,649	(206,509)	5
Merced Irrigation District (MeID)	125,555	123,933	71,893	63,218	*	2
Modesto Irrigation District (MID)	635,853	626,783	330,170	286,821	*	3
Moreno Valley Utility (MVU)	48,066	47,869	23,629	22,682	-	-
Pacific Gas and Electric Company (PG&E)	13,265,588	13,314,998	4,419,595	4,742,899	(405,607)	84
PacifiCorp	382,023	378,174	192,871	179,191	-	-
Pasadena Water and Power	562,639	561,811	136,316	130,695	-	-
Pittsburg Power Company	5,418	5,385	2,455	2,298	-	-
Plumas-Sierra REC	25,018	24,994	9,120	8,725	-	-
Port of Oakland	19,426	19,236	9,206	8,440	-	-
Port of Stockton	6,366	6,337	3,105	2,969	-	-
Power and Water Resources Pooling Authority (PWRPA)	69,635	69,635	22,367	22,367	-	-
Rancho Cucamonga Municipal Utility	22,619	22,527	11,120	10,674	-	-
Redding Electric Utility	128,290	125,531	54,784	42,121	-	-
Roseville Electric	293,897	289,759	143,819	123,815	-	-
Sacramento Municipal Utility District (SMUD)	2,136,874	2,136,534	908,263	864,544	*	1
San Diego Gas & Electric (SDG&E)	5,631,950	5,651,508	2,566,984	2,675,454	*	2

	2021		2030		Industrial Covered Entities	
Electrical Distribution Utility	**Method 1: Change Load, RPS 33-50%**	**Method 2: Fixed Load, RPS 33-50%**	**Method 1: Change Load, RPS 33-50%**	**Method 2: Fixed Load, RPS 33-50%**	**2021 Adjustment***	**Number of Entities**
Silicon Valley Power (SVP), City of Santa Clara	614,029	608,477	263,772	241,806	*	2
Southern California Edison (SCE)	20,793,217	20,973,477	8,922,790	9,642,588	(719,047)	49
Surprise Valley Electrification Corp.	2,613	2,613	1,634	1,634	-	-
Truckee Donner Public Utilities District	46,623	46,423	22,961	21,997	-	-
Turlock Irrigation District (TID)	385,531	379,185	187,772	155,104	*	3
Valley Electric Association, Inc.	2,266	2,266	970	970	-	-
Victorville Municipal Utility Services	22,336	22,245	10,981	10,541	-	-
WAPA - Sierra Nevada Region	157,351	152,937	23,483	5,719	-	-
TOTAL	**59,132,904**	**59,281,039**	**22,530,196**	**23,235,584**	**(1,503,333)**	**156**