Air Resources Board

PUBLIC MEETING AGENDA

OCTOBER 19, 2006
9:00 a. m.

Agenda Items to be heard;

06-9-1: 06-9-2: 06-9-3:

06-9-4: 06-9-5: 06-9-6

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California Environmental Protection Agency

ELECTRONIC BOARD BOOK

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

LOCATION:
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814

This facility is accessible by public transit. For transit information, call (916) 321-BUSS, website: http://www.sacrt.com
(This facility is accessible to persons with disabilities.)

October 19, 2006
9:00 a.m.

Item #

06-9-1: Report to the Board on a Health Update: Air Pollution and Infant Mortality in California

One of the most troubling health impacts of air pollution is the association of air pollution exposure and death. Although the elderly have long been considered at risk from the mortality effects of pollution exposure, recent studies have indicated that infants may also be vulnerable to mortality impacts. We will present two new studies based in California that examined the impact of air pollution exposure and infant death. These studies found that particulate matter exposure was associated with an increased risk of death in infants in California. The risk of respiratory-related deaths was more than doubled for infants exposed to higher levels of particulate matter in one study. These studies provide evidence that support our need to set ambient air quality standards to protect our sensitive populations, including the very young.

06-9-2: Report to the Board on the Air Resources Board's Role and Responsibilities in Addressing Climate Change

Staff will update the Board on the role and responsibilities of the ARB in meeting the state's greenhouse gas reduction targets set forth by Governor Schwarzenegger in Executive Order S-3-05 and by the Legislature in recently enacted AB 32.

06-9-3: Public Meeting to Update the Board on the Air Resources Board's 2006 Legislative Office Report

Legislative Director Rob Oglesby will provide a brief review of major air quality related developments in the California Legislature during 2006.

06-9-4: Public Hearing to Consider Amendments to the Zero Emission Bus (ZEB) Regulation

Staff is proposing amendments to the Zero Emission Bus regulation to postpone the requirement to purchase zero emission buses, and establish an Advanced Demonstration program.

06-9-5: Public Hearing to Consider Amendments to the Distributed Generation Certification Program

Pursuant to State law, ARB established a Distributed Generation Certification program in 2001 for electrical generation technologies that are exempt from local air district permits. The staff is now proposing minor amendments to the program, in part based on a recently completed technology review.

06-9-6: Public Meeting to Update the Board on Allocation of $25 Million for Alternative Fuel Incentives

Staff will provide an update to the Board on efforts to implement AB 1811, which provides $25 million to fund alternative fuels projects.

OPPORTUNITY FOR MEMBERS OF THE BOARD TO COMMENT ON MATTERS OF INTEREST.

Board members may identify matters they would like to have noticed for consideration at future meetings and comment on topics of interest; no formal action on these topics will be taken without further notice.

OPEN SESSION TO PROVIDE AN OPPORTUNITY FOR MEMBERS OF THE PUBLIC TO ADDRESS THE BOARD ON SUBJECT MATTERS WITHIN THE JURISDICTION OF THE BOARD.

Although no formal Board action may be taken, the Board is allowing an opportunity to interested members of the public to address the Board on items of interest that are within the Board's jurisdiction, but that do not specifically appear on the agenda. Each person will be allowed a maximum of three minutes to ensure that everyone has a chance to speak.

TO SUBMIT WRITTEN COMMENTS ON AN AGENDA ITEM IN ADVANCE OF THE MEETING GO TO:
http://www.arb.ca.gov/lispub/comm/bclist.php

IF YOU HAVE ANY QUESTIONS,
PLEASE CONTACT THE CLERK OF THE BOARD
1001 I Street, 23rd Floor, Sacramento, CA 95814

(916) 322-5594
FAX: (916) 322-3928
ARB Homepage: www.arb.ca.gov

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- **For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at 916-323-4916 by voice or through the California Relay Services at 711, to place your request for disability services.**
- **If you are a person with limited English and would like to request interpreter services to be available at the Board meeting, please contact ARB's Bilingual Manager at 916-323-7053.**

THE AGENDA ITEMS LISTED ABOVE MAY BE CONSIDERED IN A DIFFERENT ORDER AT THE BOARD MEETING.

SMOKING IS NOT PERMITTED AT MEETINGS OF THE CALIFORNIA AIR RESOURCES BOARD

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

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INDEX

October 19, 2006
9:00 a.m.

CALIFORNIA
Climate
ACTION TEAM

Executive Summary

Climate Action Team Report to
Governor Schwarzenegger
and the California Legislature

March 2006

CALIFORNIA ENVIRONMENTAL
PROTECTION AGENCY

THE CLIMATE ACTION TEAM REPORT IS ORGANIZED IN 3 VOLUMES

1. CLIMATE ACTION TEAM REPORT

- Executive Summary
- Climate Action Team Report to Governor Schwarzenegger and the Legislature

2. ATTACHMENTS

- Documentation of Inputs to Macroeconomic Assessment
- Climate Action Team Questions & Answers
- State of California's Action to Address Global Climate Change
- State Agency Work Plans
- Cap and Trade Program Design Options
- Learning from State Action on Climate Change
- Scenarios of Climate Changes in California

3. APPENDICES

- An Assessment of Impacts of Future CO2 and Climate on Agriculture
- Analysis of Climate Effects on Agricultural Systems
- Climate Change: Challenges and Solutions for California Agricultural Landscape
- Climate Change and Wildfire in and Around California: Fire Modeling and Loss Modeling
- The Response of Vegetation Distribution, Ecosystem Productivity, and Fire in California Climate Scenarios Simulated by the MCI Dynamic Vegetation Model
- Fire and Sustainability: Considerations for California's Altered Future Climate

APPENDICES (CONTINUED)

- Climate Change Impacts on Forest Resources
- Climate Change Impacts on Water for Agriculture in California: A Case Study in the Sacramento Valley
- Climate Warming and Water Supply Management in California
- Predicting the Effects of Climate Change on Wildfire Severity and Outcomes in California Preliminary Analysis
- Public Health-Related Impacts of Climate Change
- Preparing for the Impacts of Climate Change in California: Opportunities and Constraints for Adaptation
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- Predictions of Climate Change Impacts on California Water Resources Using CALSIM II: A Technical Note
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- Projecting Future Sea Level
- Climate Scenarios for California
- Climate Change: Projected Santa Ana Fire Weather Occurrence
- Incorporating Climate Change into Management of California's Water Resources

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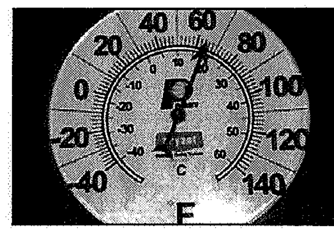
Introduction

Climate change is widely recognized by scientists throughout the world to be one of the most daunting challenges of our time. Human activities are altering the chemical composition of the atmosphere through the rapid buildup of climate change emissions—primarily carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. Concentrations of these gases in the ambient atmosphere are increasing at a rate not experienced for millions of years, according to ice core samples and other scientific studies.

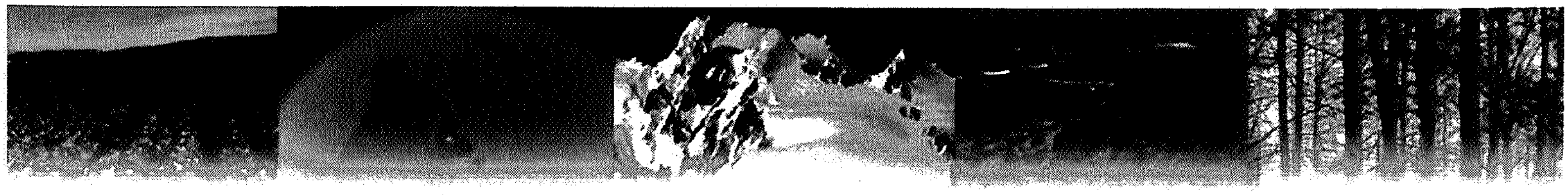
Although there is some uncertainty about exactly how and when the earth's climate will respond to increasing concentrations of climate change emissions, observations—in conjunction with climate models—indicate that detectable changes are underway.



These observed changes go beyond a global mean rise in temperature and include changes in regional temperature extremes, precipitation, soil moisture, and sea level. All of these changes could have significant adverse effects on water resources and ecological systems, as well as on human health and the economy. Implementation of precautionary and proactive measures is imperative if climate change emissions are to be reduced and communities are to adapt successfully to the adverse impacts.

California is the twelfth largest source of climate change emissions in the world, exceeding most nations. Actions taken in this State make a difference; not only because we are a major contributor to the problem but also because California is known throughout the world as a leader in addressing public health and environmental issues.

California has long been a pioneer in studying the impact of climate change and taking action to reduce our carbon "footprint." The California Energy Commission's energy efficiency standards for buildings and appliances are the most stringent in the world. The California Air Resources Board's vehicle climate change standards are the first of their kind in the United States. The State's Renewable Portfolio Standard was accelerated by Governor Schwarzenegger to require, by 2010, that 20% of all power used in California be generated from renewable resources. The California Public Utilities Commission recently adopted Governor Schwarzenegger's Solar Building Initiative that continues California's progressive approach to economic growth and technological innovation hand-in-hand with protection of public health and the environment.



On June 1, 2005, Governor Schwarzenegger signed an Executive Order establishing climate change emission reduction targets for the State and declared, ***"...the debate is over. We know the science. We see the threat. And we know the time for action is now."*** The Executive Order placed Cal/EPA as the lead coordinating State agency. The Secretary of Cal/EPA created a multi-agency team, the Climate Action Team, to meet the directives in the Executive Order.

California companies have acted voluntarily in support of the Governor's targets. More than 60 companies have joined the voluntary California Climate Action Registry; are reporting their emissions; and are discovering best practices to reduce emissions further. In the Silicon Valley, dozens of corporations have committed to significantly reducing climate change emissions.

The Climate Group, an independent, nonprofit organization dedicated to advancing business and government leadership on climate change, tracks climate change emission reduction efforts of Fortune 500 companies such as DuPont, Honda, Johnson and Johnson, and Kodak. The Climate Group reports on emissions reduced and dollars saved by these companies through voluntary actions.

Technologies that reduce climate change emissions are increasingly in demand in the world marketplace. California companies are both investing in those technologies and finding new opportunities to meet this demand.

Public Process

In preparation of this report, the Climate Action Team conducted nine public meetings. More than 100 individuals and representatives of organizations presented testimony. Since the Climate Action Team released its initial draft report in December 2005, more than 15,000 comments have been submitted. The comments overwhelmingly praise the efforts of the Climate Action Team and recognize that climate change is a serious problem facing California. They are primarily supportive of strategies to reduce climate change emissions and develop adaptation measures to mitigate the inevitable adverse consequences.

Comments ranged in specificity. Comments expressed most often were:

- The State should establish a cap on emissions and a market-based system of emissions trading, auctioning, and/or offsets. These commenters assert that a firm and statutory cap on emissions will provide the signal that will challenge Californians to reduce climate change emissions in the most cost-effective manner. Further, these commenters believe a firm cap and/or market-based approach will stimulate market innovation and grow the economy.
- Alternatively, some commenters said that California should take a slower approach that builds on voluntary efforts. Many of these commenters also prefer that climate change be addressed on a national or international level.
- A number of commenters wanted the State to conduct additional analyses of the impacts of climate change on low-income and minority communities.

Key Recommendations

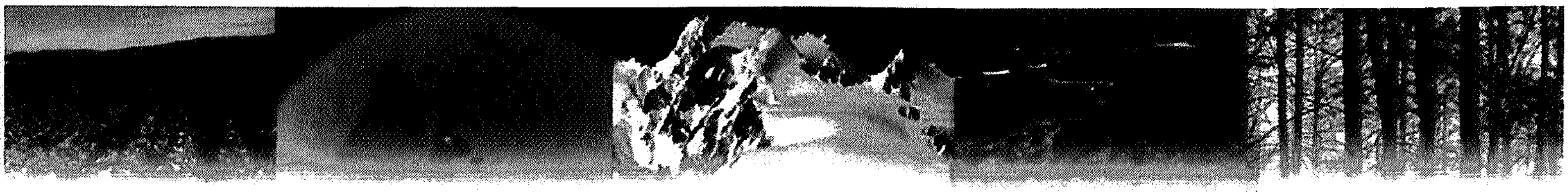
This final report has been revised from the December 2005 draft to reflect the comments, recommendations, and suggestions that have been submitted. The final report proposes a path to achieve the Governor's targets that will build on voluntary actions of California businesses, local government and community actions, and State incentive and regulatory programs.
The Governor's climate change emission reduction targets are achievable with economic benefit for California.

The climate strategies set forth in this report are in various stages of development. Some of the strategies, such as the California Solar Initiative, are being implemented this year. Other strategies, such as those related to biofuels, may require statutory modification this year for implementation to proceed. Still others, such as Smart Land Use and Intelligent Transportation and Semiconductor Industry Targets are conceptually sound but require further analysis and development over the next two years. The Climate Action Team preliminary economic assessment, which is based on the Environmental Dynamic Revenue Model, indicates that implementation of these strategies will result in 83,000 new jobs and an increase in personal income of $4 billion by 2020.

The Climate Action Team process for developing this report has been successful and the Team should be charged with the next phase of activity. Since the signing of the Executive Order, the Climate Action Team, under the leadership of Cal/EPA, has provided a forum for coordinating State agency actions, program development, and budget proposals in addition to this report. Continuing allows for collaboration, reduced internal competition and conflict, and provides a single point of contact.

The Climate Action Team recognizes that reducing climate change emissions is challenging and will need to be addressed in a deliberative on-going manner. The Team also recognizes that many of the reductions will come from technological innovations that are not yet fully developed. We have identified key recommendations that will help ensure the Governor's targets are met:

- A multi-sector, market-based system uses economic incentives to lower costs, protect economic growth, and promote innovation. The Climate Action Team should proceed with the development of a multi-sector, market-based program which considers trading, emissions credits, auction, and offsets. The Climate Action Team should develop a multi-sector, market-based program and make a recommendation to the Governor on the structure for such a program no later than January 1, 2008. The Governor's 2020 climate change emission reduction target (to reach 1990 emission levels) should be the basis for an emissions cap in the development of the program. The Climate Action Team should consider working with other western States to develop a multi-State program to minimize emissions leakage.



- Mandatory emissions reporting from the largest sources—oil and gas extraction, oil refining, electric power, cement manufacturing, and solid waste landfills—that build on the California Climate Action Registry, is essential. Mandatory reporting will ensure an accurate inventory of emissions, which is critical to ensure that decision-making is based on real emissions and emission reductions. Equally essential are provisions for early action credit and a mechanism to ensure that companies are not penalized for early action. Early action will be attributed to California businesses that have voluntarily joined the California Climate Action Registry and have reduced emissions. Although the voluntary Climate Action Registry provides the foundation, the Climate Action Team believes mandatory reporting must occur through a State government agency.
- A multi-generational public education campaign should be implemented to ensure that the public is informed about the issue of climate change and what they can do to reduce emissions and adapt to adverse consequences. Such a program can build upon successful campaigns in place, such as Flex Your Power. The Education and the Environment Initiative mandates the development of a unified strategy to bring education about the environment into California's K–12 schools through California's Environmental Principles & Concepts and a standards-aligned, State Board of Education-approved model curriculum. It is essential that California's children understand the impacts and consequences of climate change on the State's resources as well as mitigation and adaptation strategies.
- The macroeconomic analysis should be updated to reflect refined data collected over the next year. A cost-effectiveness analysis of all the strategies recommended in this report should also be developed. Both should be completed by July 2007 and should incorporate an external review process.
- Transportation is the largest source of climate change emissions in California. The California Air Resources Board's vehicle climate change standards address a significant portion of the transportation sector. However, an aggressive alternative fuels program will significantly reduce climate change emissions. The California Energy Commission, working with Cal/EPA and its boards and departments and the California Department of Food and Agriculture, are currently developing an aggressive biofuels program that will be available this Spring. This biofuels program should be considered an essential component of the effort to reduce California's carbon footprint.
- The Governor's climate change emission reduction targets are based in part on the planning assumptions in the California Energy Commission's Integrated Energy Policy Report. Specifically, the report recommends that all long-term commitments to new electricity generation for use in the State must come from sources with climate change emissions equivalent to or less than a new combined cycle natural gas power plant. The California Public Utilities Commission's recently adopted proposal for an electricity sector carbon policy is generally consistent with the Integrated Energy Policy Report and will set forth a regulatory scheme for enforcing such a policy applicable to investor-owned utilities.

The Climate Action Team recommends the policy, including an accountability mechanism, in the Integrated Energy Policy Report be extended to apply to all load-serving entities in the State, including municipal utilities, electric service providers, and community choice aggregators. The California Public Utilities Commission will work with the Climate Action Team so that this effort is consistent with the development of a multi-sector market-based program.

- All utilities should meet the energy efficiency goals and the Renewable Portfolio Standard required of investor-owned utilities. The State has adopted energy efficiency goals and a Renewable Portfolio Standard for investor-owned utilities. Publicly-owned utilities should match this level of performance and account for their achievements in a manner consistent with that of investor-owned utilities. Because publicly-owned utilities provide 25% to 30% of the electricity used in California, these entities are essential to the State's overall goal to reduce electricity demand and increase the State's use of renewable resources. The California Energy Commission should work with the publicly-owned utilities to develop an accurate accounting system that captures climate emission reduction efforts by publicly-owned utilities so that their performance can be evaluated comparatively to investor-owned utilities.

- The California Climate Action Registry, in cooperation with the California Energy Commission, should develop emission reporting protocols for local government. Local governments are already contributing to the effort to reduce climate change emissions and an accurate tracking system of their contributions is essential.

- Over time, funding will be needed to implement the strategies set forth in this plan and to provide incentives for industry to develop emission reduction technologies for use in California and abroad. A coordinated investment strategy can leverage the talent of California's universities, community colleges, and other entities to lead technology development and train the next generation of technicians that will be needed to operate and service those technologies. A public goods charge for transportation that funds key strategies to reduce climate change emissions and to reduce dependence on petroleum should be considered. Over dependence on petroleum fosters undesirable geopolitical, economic, energy, and environmental consequences. Other possible funding could come from the Public Interest Energy Research program at the California Energy Commission, other State funds, or philanthropic and corporate investment. The current electricity sector and natural gas public goods charges should continue at projected levels. Any new funding concepts require additional study and review until the preliminary recommendations noted above can be more fully developed. Accordingly, the 2006–07 Governor's budget proposes $7.2 million across several State agencies to begin the additional work.

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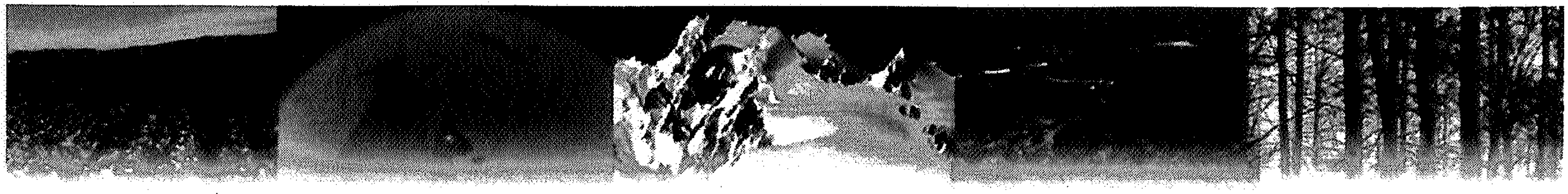


Executive Order S-3-05

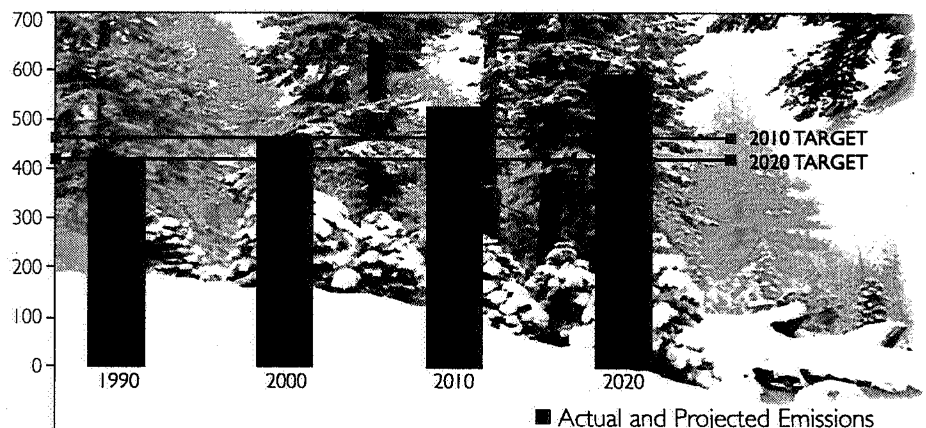
In recognition of the risks associated with climate change and the imperative for California to act, Governor Schwarzenegger signed Executive Order S-3-05. This Executive Order established Statewide climate change emission reduction targets:

- By 2010, reduce emissions to 2000 levels;
- By 2020, reduce emissions to 1990 levels;
- by 2050, reduce emissions to 80 percent below 1990 levels.

The red and blue lines in figure ES-1 illustrate Governor Schwarzenegger's target.

Figure ES-1

California's Climate Change Emissions and Targets



The Executive Order also directed the Secretary for Environmental Protection to prepare a report to the Governor and the Legislature by January 2006 that defines actions necessary to meet the Governor's targets. This effort is to be coordinated with other key agencies to ensure the targets are met. Progress towards meeting the targets must be provided in subsequent reports every two years. These reports must also include scientific analysis of climate change impacts on the State and adaptation measures that can be taken to best respond to the adverse consequences of climate change.

Consistent with the directives of the Executive Order, a Climate Action Team was formed. The Team is comprised of knowledgeable representatives from the following State agencies:

- Business, Transportation and Housing Agency;
- Department of Food and Agriculture;
- Resources Agency;
- Air Resources Board;
- Energy Commission;
- Integrated Waste Management Board; and
- Public Utilities Commission.

The Climate Action Team has developed a list of emission reduction strategies that could meet the Governor's targets. Further, the Climate Action Team reviewed the work by some of California's top scientists regarding the impacts of climate change on California and potential adaptation measures to combat adverse impacts.

Strategies Recommended to Reduce Climate Change Emissions

The strategies being recommended by the Climate Action Team are shown in Tables ES-1 through ES-4. Although the Climate Action Team recommends additional development on all of these strategies at this time, the implementing agencies will proceed through their existing regulatory, public, and stakeholder processes for each of the strategies. Modifications to the strategies may be necessary as a result of those processes. Additional strategies may also emerge over time. Modifications and additions will be made as appropriate over the course of the Climate Action Team report updates.

Many of the strategies listed in Tables ES-1 through ES-4 also reduce ozone and criteria and toxic pollutants. (Criteria pollutants are a type of pollutant: oxides of nitrogen, carbon monoxide, and hydrocarbons). Although the degree to which they contribute to climate change has not been fully quantified, ozone, most criteria pollutants, and particulate matter emissions are being evaluated for their climate-forcing potential. Further iterations of this report will update the Governor and Legislature on the results.

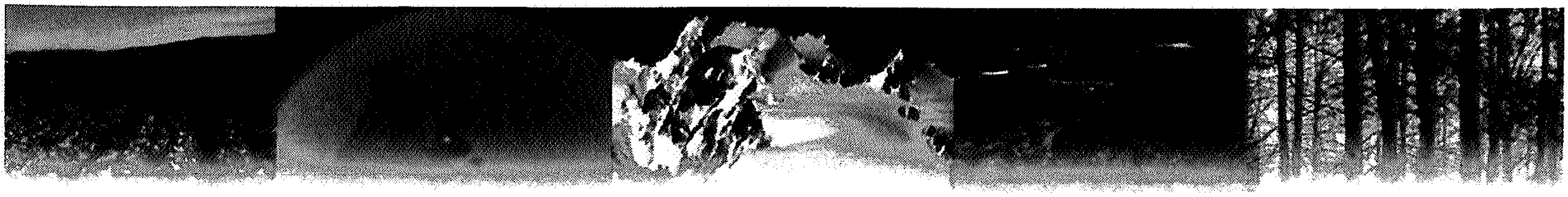


Table ES-1 lists all of the strategies that Cal/EPA will implement over the next two years. By 2020, the Air Resources Board's vehicle climate change emission standards will provide the largest emission reductions of any of the strategies being recommended by the Climate Action Team. The large auto manufacturers are currently challenging California's right to set climate change emission standards for vehicles. Governor Schwarzenegger has pledged his support in defending the State's right to require the sale of cleaner cars.

Table ES-1

Environmental Protection Agency

Climate Change Emission Reductions (Million Metric Tons CO_2 Equivalent)	2010	2020
• ***Air Resources Board***		
· Vehicle Climate Change Standards	1	30
· Diesel Anti-Idling	1	1.2
· Other New Light Duty Vehicle Technology Improvements	0	4
· HFC Reduction Strategies	2.7	8.5
· Transport Refrigeration Units, Off-Road Electrification, Port Electrification (ship to shore)	<1	<1
· Manure Management	0	1
· Semi Conductor Industry Targets (PFC Emissions)	2	2
· Alternative Fuels: Biodiesel Blends	<1	<1
· Alternative Fuels: Ethanol	<1	<3.2
· Heavy-Duty Vehicle Emission Reduction Measures	0	3
· Reduced Venting and Leaks in Oil and Gas Systems	1	1
· Hydrogen Highway	Included•	
• ***Integrated Waste Management Board***		
· Achieve 50% Statewide Recycling Goal	3	3
· Landfill Methane Capture	2	3
· Zero Waste—High Recycling	3	

•The benefits of the Hydrogen Highway have been captured in other programs such as the Vehicle Climate Change Standard and Green Buildings Initiative.

Table ES-2 lists all of the strategies that Resources Agency will implement over the next two years. The Forest management efforts promise not only climate change emission reductions but also protect biodiversity, water quality and habitat resources. For three decades, the California Energy Commission has led the world with the most progressive new building and appliance efficiency standards. These efficiency standards have provided substantial climate change emission reductions and have saved consumers about $1,000 per household in California. Finally, by reducing the energy used to transport and deliver water in the State and by increasing water use efficiency, California can both protect our water supply and reduce climate change emissions.

Table ES-2
Resources Agency

Climate Change Emission Reductions (Million Metric Tons CO_2 Equivalent)	2010	2020
• ***Department of Forestry***		
· Forest Management	1-2	2-4
· Forest Conservation	4.2	8.4
· Fuels Management/Biomass	3.4	6.8
· Urban Forestry	0	3.5
· Afforestation/Reforestation	0	12.5
• ***Energy Commission***		
· Building Energy Efficiency Standards in Place	1	2
· Appliance Energy Efficiency Standards in Place	3	5
· Fuel-Efficient Replacement Tires & Inflation Programs	1.5	1.5
· Building Energy Efficiency Standards in Progress	TBD	TBD
· Appliance Energy Efficiency Standards in Progress	TBD	TBD
· Cement Manufacturing	<1	<1
· Municipal Utility Energy Efficiency Programs/Demand Response	1	5.9
· Municipal Utility Renewable Portfolio Standard	<1	3.2
· Municipal Utility Combined Heat and Power	0	<1
· Municipal Utility Electricity Sector Carbon Policy	3	9
· Alternative Fuels: Non-Petroleum Fuels	TBD	TBD
· Building Energy Efficiency Standards in Place	1	2
• ***Department of Water Resources***		
· Water Use Efficiency	0.4	1.2

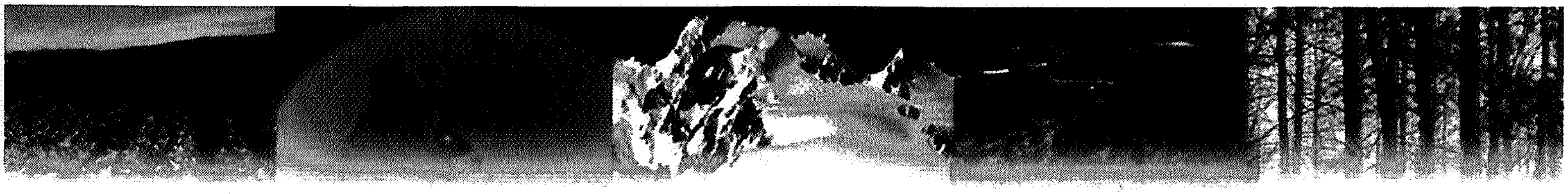


Table ES-3 lists all of the strategies that other State agencies will implement over the next two years. Many participants at the Climate Action Team public meetings, particularly in Southern California, indicated that smart land use and increased transit availability should be a priority in the State. The participation of Business, Transportation and Housing Agency on the Climate Action Team has highlighted the fact that such strategies can provide substantial climate change emission reductions. Similarly the efforts of the Department of Food and Agriculture and the State and Consumer Services Agency provide benefits beyond their climate change emission reduction potential.

Table ES-3

Other State Agencies

Climate Change Emission Reductions (Million Metric Tons CO_2 Equivalent)	2010	2020
• ***Business Transportation and Housing***		
· Measures to Improve Transportation Energy Efficiency	1.8	9
· Smart Land Use and Intelligent Transportation	5.5	18
• ***Department of Food and Agriculture***		
· Conservation Tillage/Cover Crops	TBD	
· Enteric Fermentation	<1	<1
• ***State and Consumer Services Agency***		
· Green Buildings Initiative	0.5	1.8
· Transportation Policy Implementation	Under Review	

x

Table ES-4 lists all of the strategies that the Public Utilities Commission will implement over the next two years. Working in cooperation with the Energy Commission, the Public Utilities Commission has implemented the most progressive Renewable Portfolio Standard in the nation. The Public Utilities Commission has also been progressive in energy efficiency and clean energy programs for investor-owned utilities. Many stakeholders indicated that these programs should apply to the publicly-owned utilities as well.

Table ES-4

Public Utilities Commission

Climate Change Emission Reductions (Million Metric Tons CO_2 Equivalent)	2010	2020
• Accelerated Renewable Portfolio Std to 33% by 2020 (includes load-serving entities)	5	11
• California Solar Initiative	0.4	3
• Investor-Owned Utility (IOU) Energy Efficiency Programs (including LSEs)	4	8.8
• IOU Additional Energy Efficiency Programs/Demand Response	NA	6.3
• IOU Combined Heat and Power Initiative	1.1	4.4
• IOU Electricity Sector Carbon Policy	1.6	2.7

The Governor's Targets Are Achievable

Based on the emission reduction potential demonstrated in the tables above, and illustrated in Figure ES-2 below, it is clear the Governor's targets are achievable. However, continued top-down leadership—as has been demonstrated by this Governor, and the coordinated agency-level effort that has been achieved via the Climate Action Team—will be essential to success.

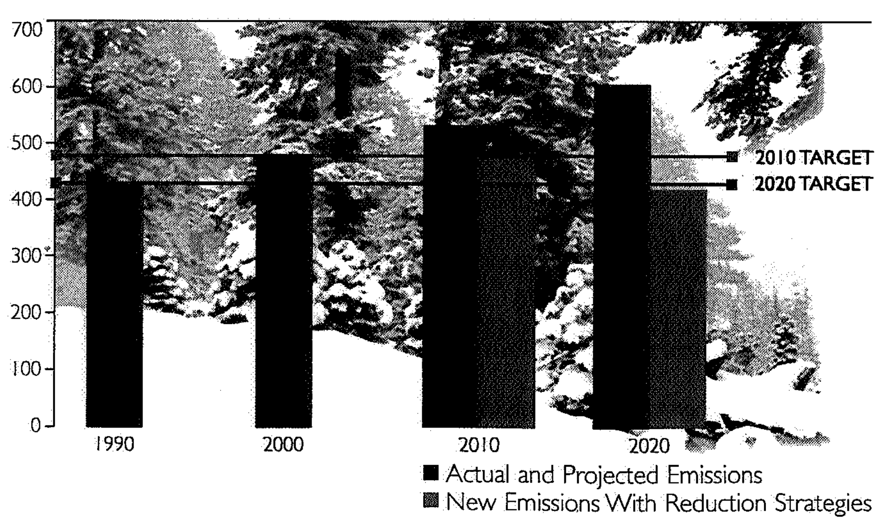
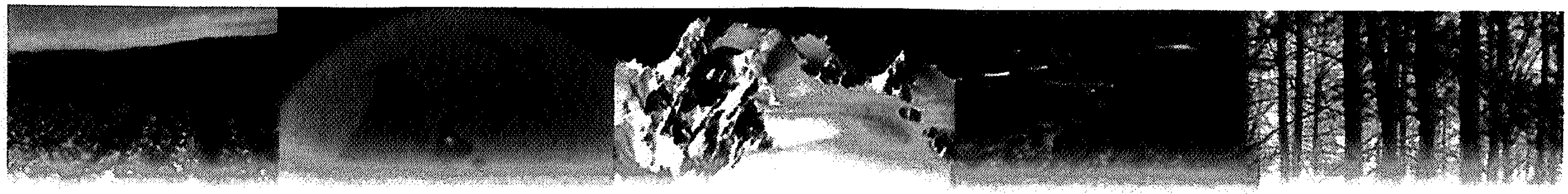


Figure ES-2

California Climate Change Emissions and Targets After Implementing Emission Reduction Strategies

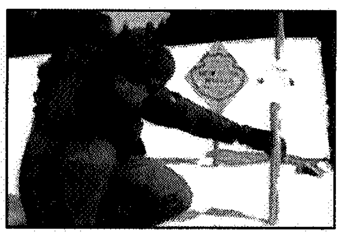


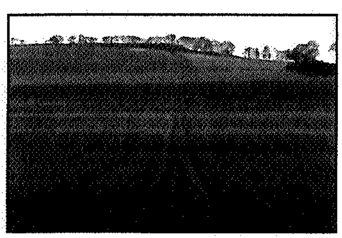
Scenario Analysis

The scientific analysis to determine the impacts of climate change on California, and potential adaptation measures, is referred to here as the Scenario Analysis. Three scenarios of future global climate change emissions were selected to determine the range of possible impacts from climate change. These scenarios come directly from the Intergovernmental Panel on Climate Change 2001 report and represent higher, medium-high, and low-emission scenarios.

This analysis considers impacts on water resources, public health, agriculture, coastline, forests, and electricity demand based on the three emission scenarios. The analysis in this report stems directly from the ongoing work being done by the California Energy Commission. It represents a mid-point check in the current five-year plan that the California Energy Commission has underway to evaluate climate change impacts in the State.

The analysis indicates that if emissions are not reduced significantly, there is a strong likelihood that the amount of warming toward the end of the century will exceed 3 °F. In the analyses, as the warming increases above this level to as much as 10 °F, some of the consequences of climate change in California may become quite severe, including:

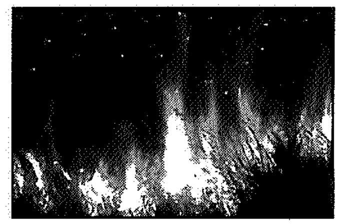




- Sierra snowpack, which accounts for approximately half of the surface water storage in the State, would decline by 70% to as much as 90% over the next 100 years, threatening California's water supply.
- Climate change will slow progress toward attainment of air quality standards and increase control costs by increasing emissions, accelerating chemical processes, and raising inversion temperatures during summertime stagnation episodes. The number of days meteorologically conducive to pollution formation may rise by 75% to 85% in the high ozone areas of Los Angeles and the San Joaquin Valley by the end of the century under the higher temperature scenario, and by 25% to 35% under the lower temperature scenario.
- The agriculture industry is one of the largest industries in the State. Potential impacts from limited water storage, increasing temperatures, and salt water in the Sacramento and San Joaquin Delta would pose increasing challenges for this industry. Direct threats to the structural integrity of the State's levee and flood control systems would also have immense implications for the State's fresh water supply, food supply, and overall economic prosperity.

- Higher potential for erosion of California's coastlines and sea water intrusion into the State's Delta and levee systems may result as sea levels rise above present levels by as much as 35 inches during the next 100 years. This would exacerbate flooding in already vulnerable regions.

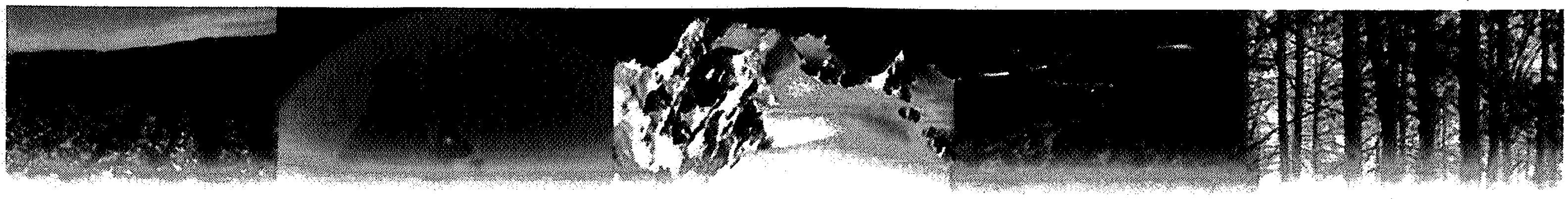
- Pest infestation and increasing temperatures would make the State's forest resources more vulnerable to fires. Forest fires not only adversely affect the State's economy as a result of both suppression and damage costs, they also decrease air quality, damaging public health and visibility.
- Rising temperatures will increase electricity demand, especially in the hot summer season. By 2020, this would translate to a 1% to 3% increase in electricity demand resulting in potentially hundreds of millions of extra expenditures.



These impacts will affect everyone. However, in many cases, the most vulnerable are children, the elderly, and the frail who suffer disproportionately when pollution increases and temperatures rise. Low-income and minority communities are also at greater risk as limited resources and current disparities in health care limit the capacity of residents in these communities to adapt and respond.

The scenario analysis also included an evaluation of adaptation measures that could be taken to respond to the adverse consequences of climate change. This evaluation is only beginning, but at this point, the adaptation measures identified include the following:

- Study and use modern probabilistic weather and hydrological forecasts for the management of water reservoirs and other resources in the State.
- Develop and implement heat emergency action plans with special emphasis on providing assistance to the elderly and those living in housing without air conditioning units.
- Adopt short-term actions to improve our ability to live within California's fire-prone landscapes while maintaining the functioning and structure of ecosystems upon which we depend.
- Mitigate the impact of high temperatures on electricity demand with energy efficiency programs, increased penetration of photovoltaic systems and other forms of renewable energy, and the implementation of measures designed to reduce the urban heat island effect.



Market-Based Options For California

Market-based programs can be integral to California's strategy for reducing climate change emissions. Establishing firm attainment directives for reduction of greenhouse gas emissions, coupled with a market-based program, allows for flexibility in meeting a cap at the least possible cost.

To maximize its effectiveness, a market-based program in California should encompass as many sources and as large a geographic region as possible. However, the breadth of coverage must be tempered by administrative realities and source-specific considerations. Two alternatives for defining the scope of California's market-based program are a sector-based emissions cap and a fuels-based carbon cap.

A sector-based emissions cap would cover up to 30 percent of the State's climate change emissions by focusing on five key industries: electric power (including emissions from imported electricity); oil refining; oil and gas extraction; solid waste landfills; and cement manufacturing. Mobile sources, the largest source of climate change emissions in the State, are not recommended for inclusion under a sector-based emissions cap at this time.

As an alternative to a sector-based cap, climate change emissions can be reduced by capping the total carbon content of oil, gas, and coal consumed in the State. This approach encompasses all sectors that use fossil fuels, including those indicated in the paragraph above, covering 75 percent of the State's climate change emissions. All options for reducing fossil fuel combustion across all sectors can contribute to achieving the carbon cap. Additionally, all sectors are put on an equal footing as it relates to their use of fossil fuels.

A hybrid approach can be considered, for example, in which emissions from the electric power industry (including imported power) are capped and the carbon content of fuels is capped.

Emission offsets can be used to motivate emission reductions from sources outside the cap. Emission offsets help lower the cost of reducing emissions: facilities covered by the cap can purchase low-cost emission reductions from outside the cap as a means of complying with their emission limit. To ensure that offsets do not compromise the emission reduction goal of the program, they must be real, verifiable, quantifiable, in excess to any regulatory requirement, and not counted toward any other climate change emission reduction targets.

The primary weakness associated with implementing a market-based program in California is that it will be vulnerable to emission "leakage." If the State implements the program without other States, there will be an incentive for production to shift to neighboring States to avoid the cap. If this occurs, emissions may decline in the State, only to increase in neighboring States. A coordinated national approach to capping climate change emissions within an international framework would be the best approach for addressing this leakage problem. In the absence of national action, or even regional action, the leakage issues may be partially addressed through the design of the program. As part of the implementation of a market-based program, data should be collected over time to assess the extent to which leakage occurs, as well as its impacts on businesses and on the effectiveness of the emissions cap.

Economic Impact

This report also provides the results of a preliminary assessment of the macroeconomic impacts associated with the climate change emission reduction strategies. The results show that the overall impacts of the climate change emission reduction strategies on California's economy are expected to be positive. Specifically, when the emission reduction strategies are considered in total, the resulting impacts on the economy are expected to translate into job and income gains for Californians. For example, in 2020, the implementation of the strategies is expected to result in a net increase of 83,000 jobs and $4 billion, in income, above and beyond the substantial growth that will occur between today and 2020.

The macroeconomic assessment relies on a computable general equilibrium model developed by the University of California, Berkeley called the Environmental Dynamic Revenue Model. This model has been peer reviewed and calibrated to be representative of the California economy. It simulates the functioning of a market economy in which different sectors interact with one another (one sector supplies inputs to another, or purchases the outputs of another) and where prices and production adjust in response to changes caused by government policies applied to specific sectors. The model simulates these relationships among California producers, California consumers, government, and the rest of the world. Because of the interconnection between sectors, an intervention in one sector has impacts on others, which are captured by the model analysis. This model has long been used by the California Air Resources Board and California Energy Commission in the development of certain of their reports and regulations. The Department of Finance also uses a version of this model to determine the revenue impacts of State policies.

The favorable impacts on the economy are possible because of the reduced costs associated with many of the strategies. The additional job growth is expected to come from the net savings to consumers associated with the implementation of the strategies. The savings will, in turn, promote further business expansion and job creation.

A subsequent refined analysis is planned over the next year. The refined analysis will incorporate updated cost and savings estimates for the strategies. It will also assess the cost-effectiveness of the various individual strategies. Thus, the refined economic analysis will provide additional information to decision-makers as they proceed with implementation of the strategies.

Impacts On Low Income And Minority Communities

Cal/EPA has made the achievement of environmental justice an integral part of its activities. Cal/EPA adopted its intra-agency Environmental Justice Strategy in August 2004 and its Environmental Justice Action Plan in October 2004. These policies establish a framework for incorporating environmental justice into Cal/EPA's programs, consistent with the directives of California State law.

As the Climate Action Team developed this report to the Governor and the Legislature, Cal/EPA staff worked with community leaders involved with environmental justice and with environmental and public health organizations to maintain an ongoing dialogue. This approach has worked to successfully implement the administration's environmental justice policies.

The Climate Action Team has undertaken an evaluation to investigate if low-income and minority communities may be impacted disproportionately by climate change, efforts to adapt to climate change, and/or efforts to reduce climate change emissions.

Each agency represented on the Climate Action Team has agreed to incorporate environmental justice considerations into their efforts to support the directives of the Executive Order. To the extent possible, environmental justice considerations are included in the agencies' work plans to implement strategies that reduce climate change emissions.

Climate Website:
www.climatechange.ca.gov

Printed Using Soy Based Ink

Assembly Bill No. 32

Passed the Assembly August 31, 2006

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Chief Clerk of the Assembly

Passed the Senate August 30, 2006

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Secretary of the Senate

This bill was received by the Governor this _____ day of _______________, 2006, at _____ o'clock ____M.

____

Private Secretary of the Governor

CHAPTER ________

An act to add Division 25.5 (commencing with Section 38500) to the Health and Safety Code, relating to air pollution.

LEGISLATIVE COUNSEL'S DIGEST

AB 32, Nunez. Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006.

Under existing law, the State Air Resources Board (state board), the State Energy Resources Conservation and Development Commission (Energy Commission), and the California Climate Action Registry all have responsibilities with respect to the control of emissions of greenhouse gases, as defined, and the Secretary for Environmental Protection is required to coordinate emission reductions of greenhouse gases and climate change activity in state government.

This bill would require the state board to adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program, as specified. The bill would require the state board to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020, as specified. The bill would require the state board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions, as specified. The bill would authorize the state board to adopt market-based compliance mechanisms, as defined, meeting specified requirements. The bill would require the state board to monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board, pursuant to specified provisions of existing law. The bill would authorize the state board to adopt a schedule of fees to be paid by regulated sources of greenhouse gas emissions, as specified.

Because the bill would require the state board to establish emissions limits and other requirements, the violation of which would be a crime, this bill would create a state-mandated local program.

The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

The people of the State of California do enact as follows:

SECTION 1. Division 25.5 (commencing with Section 38500) is added to the Health and Safety Code, to read:

DIVISION 25.5. CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006

PART 1. GENERAL PROVISIONS

CHAPTER 1. TITLE OF DIVISION

38500. This division shall be known, and may be cited, as the California Global Warming Solutions Act of 2006.

CHAPTER 2. FINDINGS AND DECLARATIONS

38501. The Legislature finds and declares all of the following:

(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include 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.

(b) Global warming will have detrimental effects on some of California's largest industries, including agriculture, wine, tourism, skiing, recreational and commercial fishing, and forestry. It will also increase the strain on electricity supplies necessary to meet the demand for summer air-conditioning in the hottest parts of the state.

(c) California has long been a national and international leader on energy conservation and environmental stewardship efforts, including the areas of air quality protections, energy efficiency requirements, renewable energy standards, natural resource conservation, and greenhouse gas emission standards for passenger vehicles. The program established by this division will continue this tradition of environmental leadership by placing California at the forefront of national and international efforts to reduce emissions of greenhouse gases.

(d) National and international actions are necessary to fully address the issue of global warming. However, action taken by California to reduce emissions of greenhouse gases will have far-reaching effects by encouraging other states, the federal government, and other countries to act.

(e) By exercising a global leadership role, California will also position its economy, technology centers, financial institutions, and businesses to benefit from national and international efforts to reduce emissions of greenhouse gases. More importantly, investing in the development of innovative and pioneering technologies will assist California in achieving the 2020 statewide limit on emissions of greenhouse gases established by this division and will provide an opportunity for the state to take a global economic and technological leadership role in reducing emissions of greenhouse gases.

(f) It is the intent of the Legislature that the State Air Resources Board coordinate with state agencies, as well as consult with the environmental justice community, industry sectors, business groups, academic institutions, environmental organizations, and other stakeholders in implementing this division.

(g) It is the intent of the Legislature that the State Air Resources Board consult with the Public Utilities Commission in the development of emissions reduction measures, including limits on emissions of greenhouse gases applied to electricity and natural gas providers regulated by the Public Utilities Commission in order to ensure that electricity and natural gas providers are not required to meet duplicative or inconsistent regulatory requirements.

(h) It is the intent of the Legislature that the State Air Resources Board design emissions reduction measures to meet the statewide emissions limits for greenhouse gases established pursuant to this division in a manner that minimizes costs and maximizes benefits for California's economy, improves and modernizes California's energy infrastructure and maintains electric system reliability, maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to improve air quality.

(i) It is the intent of the Legislature that the Climate Action Team established by the Governor to coordinate the efforts set forth under Executive Order S-3-05 continue its role in coordinating overall climate policy.

Chapter 3. Definitions

38505. For the purposes of this division, the following terms have the following meanings:

(a) "Allowance" means an authorization to emit, during a specified year, up to one ton of carbon dioxide equivalent.

(b) "Alternative compliance mechanism" means an action undertaken by a greenhouse gas emission source that achieves the equivalent reduction of greenhouse gas emissions over the same time period as a direct emission reduction, and that is approved by the state board. "Alternative compliance mechanism" includes, but is not limited to, a flexible compliance schedule, alternative control technology, a process change, or a product substitution.

(c) "Carbon dioxide equivalent" means the amount of carbon dioxide by weight that would produce the same global warming impact as a given weight of another greenhouse gas, based on the best available science, including from the Intergovernmental Panel on Climate Change.

(d) "Cost-effective" or "cost-effectiveness" means the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential.

(e) "Direct emission reduction" means a greenhouse gas emission reduction action made by a greenhouse gas emission source at that source.

(f) "Emissions reduction measure" means programs, measures, standards, and alternative compliance mechanisms authorized pursuant to this division, applicable to sources or categories of sources, that are designed to reduce emissions of greenhouse gases.

(g) "Greenhouse gas" or "greenhouse gases" includes all of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexaflouride.

(h) "Greenhouse gas emissions limit" means an authorization, during a specified year, to emit up to a level of greenhouse gases specified by the state board, expressed in tons of carbon dioxide equivalents.

(i) "Greenhouse gas emission source" or "source" means any source, or category of sources, of greenhouse gas emissions whose emissions are at a level of significance, as determined by the state board, that its participation in the program established under this division will enable the state board to effectively reduce greenhouse gas emissions and monitor compliance with the statewide greenhouse gas emissions limit.

(j) "Leakage" means a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.

(k) "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.

(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.

(*l*) "State board" means the State Air Resources Board.

(m) "Statewide greenhouse gas emissions" means the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported. Statewide emissions shall be expressed in tons of carbon dioxide equivalents.

(n) "Statewide greenhouse gas emissions limit" or "statewide emissions limit" means the maximum allowable level of statewide greenhouse gas emissions in 2020, as determined by the state board pursuant to Part 3 (commencing with Section 38850).

Chapter 4. Role of State Board

38510. The State Air Resources Board is the state agency charged with monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases.

PART 2. MANDATORY GREENHOUSE GAS EMISSIONS REPORTING

38530. (a) On or before January 1, 2008, the state board shall adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program.

(b) The regulations shall do all of the following:

(1) Require the monitoring and annual reporting of greenhouse gas emissions from greenhouse gas emission sources beginning with the sources or categories of sources that contribute the most to statewide emissions.

(2) Account for greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state. This requirement applies to all retail sellers of electricity, including load-serving entities as defined in subdivision (j) of Section 380 of the Public Utilities Code and local publicly owned electric utilities as defined in Section 9604 of the Public Utilities Code.

(3) Where appropriate and to the maximum extent feasible, incorporate the standards and protocols developed by the

California Climate Action Registry, established pursuant to Chapter 6 (commencing with Section 42800) of Part 4 of Division 26. Entities that voluntarily participated in the California Climate Action Registry prior to December 31, 2006, and have developed a greenhouse gas emission reporting program, shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board.

(4) Ensure rigorous and consistent accounting of emissions, and provide reporting tools and formats to ensure collection of necessary data.

(5) Ensure that greenhouse gas emission sources maintain comprehensive records of all reported greenhouse gas emissions.

(c) The state board shall do both of the following:

(1) Periodically review and update its emission reporting requirements, as necessary.

(2) Review existing and proposed international, federal, and state greenhouse gas emission reporting programs and make reasonable efforts to promote consistency among the programs established pursuant to this part and other programs, and to streamline reporting requirements on greenhouse gas emission sources.

PART 3. STATEWIDE GREENHOUSE GAS EMISSIONS LIMIT

38550. By January 1, 2008, the state board shall, after one or more public workshops, with public notice, and an opportunity for all interested parties to comment, determine what the statewide greenhouse gas emissions level was in 1990, and approve in a public hearing, a statewide greenhouse gas emissions limit that is equivalent to that level, to be achieved by 2020. In order to ensure the most accurate determination feasible, the state board shall evaluate the best available scientific, technological, and economic information on greenhouse gas emissions to determine the 1990 level of greenhouse gas emissions.

38551. (a) The statewide greenhouse gas emissions limit shall remain in effect unless otherwise amended or repealed.

(b) It is the intent of the Legislature that the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020.

(c) The state board shall make recommendations to the Governor and the Legislature on how to continue reductions of greenhouse gas emissions beyond 2020.

PART 4. GREENHOUSE GAS EMISSIONS REDUCTIONS

38560. The state board shall adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part.

38560.5. (a) On or before June 30, 2007, the state board shall publish and make available to the public a list of discrete early action greenhouse gas emission reduction measures that can be implemented prior to the measures and limits adopted pursuant to Section 38562.

(b) On or before January 1, 2010, the state board shall adopt regulations to implement the measures identified on the list published pursuant to subdivision (a).

(c) The regulations adopted by the state board pursuant to this section 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.

(d) The regulations adopted pursuant to this section shall be enforceable no later than January 1, 2010.

38561. (a) On or before January 1, 2009, the state board shall prepare and approve a scoping plan, as that term is understood by the state board, for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases by 2020 under this division. The state board shall consult with all state agencies with jurisdiction over sources of greenhouse gases, including the Public Utilities Commission and the State Energy Resources Conservation and Development Commission, on all elements of its plan that pertain to energy related matters including, but not limited to, electrical generation, load based-standards or requirements, the provision of reliable and affordable electrical service, petroleum refining, and statewide fuel supplies to ensure the greenhouse gas emissions reduction activities to be adopted and implemented by the state board are complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner.

(b) The plan shall identify and make recommendations on direct emission reduction measures, alternative compliance mechanisms, market-based compliance mechanisms, and potential monetary and nonmonetary incentives for sources and categories of sources that the state board finds are necessary or desirable to facilitate the achievement of the maximum feasible and cost-effective reductions of greenhouse gas emissions by 2020.

(c) In making the determinations required by subdivision (b), the state board shall consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada, and the European Union.

(d) The state board shall evaluate the total potential costs and total potential economic and noneconomic benefits of the plan for reducing greenhouse gases to California's economy, environment, and public health, using the best available economic models, emission estimation techniques, and other scientific methods.

(e) In developing its plan, the state board shall take into account the relative contribution of each source or source category to statewide greenhouse gas emissions, and the potential for adverse effects on small businesses, and shall recommend a de minimis threshold of greenhouse gas emissions below which emission reduction requirements will not apply.

(f) In developing its plan, the state board shall identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices.

(g) The state board shall conduct a series of public workshops to give interested parties an opportunity to comment on the plan. The state board shall conduct a portion of these workshops in regions of the state that have the most significant exposure to air pollutants, including, but not limited to, communities with minority populations, communities with low-income populations, or both.

(h) The state board shall update its plan for achieving the maximum technologically feasible and cost-effective reductions of greenhouse gas emissions at least once every five years.

38562. (a) On or before January 1, 2011, the state board shall adopt greenhouse gas emission limits and emission reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions in furtherance of achieving the statewide greenhouse gas emissions limit, to become operative beginning on January 1, 2012.

(b) In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.

(2) Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

(3) Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.

(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.

(5) Consider cost-effectiveness of these regulations.

(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.

(7) Minimize the administrative burden of implementing and complying with these regulations.

(8) Minimize leakage.

(9) Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

(c) In furtherance of achieving the statewide greenhouse gas emissions limit, by January 1, 2011, the state board may adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions, applicable from January 1, 2012, to December 31, 2020, inclusive, that the state board determines will achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions, in the aggregate, from those sources or categories of sources.

(d) Any regulation adopted by the state board pursuant to this part or Part 5 (commencing with Section 38570) shall ensure all of the following:

(1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the state board.

(2) For regulations pursuant to Part 5 (commencing with Section 38570), the reduction is 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.

(3) If applicable, the greenhouse gas emission reduction occurs over the same time period and is equivalent in amount to any direct emission reduction required pursuant to this division.

(e) The 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.

(f) The state board shall consult with the Public Utilities Commission in the development of the regulations as they affect electricity and natural gas providers in order to minimize duplicative or inconsistent regulatory requirements.

(g) After January 1, 2011, the state board may revise regulations adopted pursuant to this section and adopt additional regulations to further the provisions of this division.

38563. Nothing in this division restricts the state board from adopting greenhouse gas emission limits or emission reduction measures prior to January 1, 2011, imposing those limits or measures prior to January 1, 2012, or providing early reduction credit where appropriate.

38564. The state board shall consult with other states, and the federal government, and other nations to identify the most effective strategies and methods to reduce greenhouse gases, manage greenhouse gas control programs, and to facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.

38565. The state board shall ensure that the greenhouse gas emission reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small businesses, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions.

PART 5. MARKET-BASED COMPLIANCE MECHANISMS

38570. (a) The state board may include in the regulations adopted pursuant to Section 38562 the use of market-based compliance mechanisms to comply with the regulations.

(b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.

(3) Maximize additional environmental and economic benefits for California, as appropriate.

(c) The state board shall adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits and mandatory emission reporting requirements to achieve compliance with their greenhouse gas emissions limits.

38571. The state board shall adopt methodologies for the quantification of voluntary greenhouse gas emission reductions. The state board shall adopt regulations to verify and enforce any voluntary greenhouse gas emission reductions that are authorized by the state board for use to comply with greenhouse gas emission limits established by the state board. The adoption of methodologies is exempt from the rulemaking provisions of the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code).

38574. Nothing in this part or Part 4 (commencing with Section 38560) confers any authority on the state board to alter any programs administered by other state agencies for the reduction of greenhouse gas emissions.

PART 6. ENFORCEMENT

38580. (a) The state board shall monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board pursuant to this division.

(b) (1) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division may be enjoined pursuant to Section 41513, and the violation is subject to those penalties set forth in Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(2) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division shall be deemed to result in an emission of an air contaminant for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(3) The state board may develop a method to convert a violation of any rule, regulation, order, emission limitation, or other emissions reduction measure adopted by the state board

pursuant to this division into the number of days in violation, where appropriate, for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(c) Section 42407 and subdivision (i) of Section 42410 shall not apply to this part.

PART 7. MISCELLANEOUS PROVISIONS

38590. If the regulations adopted pursuant to Section 43018.5 do not remain in effect, the state board shall implement alternative regulations to control mobile sources of greenhouse gas emissions to achieve equivalent or greater reductions.

38591. (a) The state board, by July 1, 2007, shall convene an environmental justice advisory committee, of at least three members, to advise it in developing the scoping plan pursuant to Section 38561 and any other pertinent matter in implementing this division. The advisory committee shall be comprised of representatives from communities in the state with the most significant exposure to air pollution, including, but not limited to, communities with minority populations or low-income populations, or both.

(b) The state board shall appoint the advisory committee members from nominations received from environmental justice organizations and community groups.

(c) The state board shall provide reasonable per diem for attendance at advisory committee meetings by advisory committee members from nonprofit organizations.

(d) The state board shall appoint an Economic and Technology Advancement Advisory Committee to advise the state board on activities that will facilitate investment in and implementation of technological research and development opportunities, including, but not limited to, identifying new technologies, research, demonstration projects, funding opportunities, developing state, national, and international partnerships and technology transfer opportunities, and identifying and assessing research and advanced technology investment and incentive opportunities that will assist in the reduction of greenhouse gas emissions. The committee may also advise the state board on state, regional, national, and international economic and technological developments related to greenhouse gas emission reductions.

38592. (a) All state agencies shall consider and implement strategies to reduce their greenhouse gas emissions.

(b) Nothing in this division shall relieve any person, entity, or public agency of compliance with other applicable federal, state, or local laws or regulations, including state air and water quality requirements, and other requirements for protecting public health or the environment.

38593. (a) Nothing in this division affects the authority of the Public Utilities Commission.

(b) Nothing in this division affects the obligation of an electrical corporation to provide customers with safe and reliable electric service.

38594. Nothing in this division shall limit or expand the existing authority of any district, as defined in Section 39025.

38595. Nothing in this division shall preclude, prohibit, or restrict the construction of any new facility or the expansion of an existing facility subject to regulation under this division, if all applicable requirements are met and the facility is in compliance with regulations adopted pursuant to this division.

38596. The provisions of this division are severable. If any provision of this division or its application is held invalid, that invalidity shall not affect other provisions or applications that can be given effect without the invalid provision or application.

38597. The state board may adopt by regulation, after a public workshop, a schedule of fees to be paid by the sources of greenhouse gas emissions regulated pursuant to this division, consistent with Section 57001. The revenues collected pursuant to this section, shall be deposited into the Air Pollution Control Fund and are available upon appropriation, by the Legislature, for purposes of carrying out this division.

38598. (a) Nothing in this division shall limit the existing authority of a state entity to adopt and implement greenhouse gas emissions reduction measures.

(b) Nothing in this division shall relieve any state entity of its legal obligations to comply with existing law or regulation.

38599. (a) In the event of extraordinary circumstances, catastrophic events, or threat of significant economic harm, the Governor may adjust the applicable deadlines for individual regulations, or for the state in the aggregate, to the earliest feasible date after that deadline.

(b) The adjustment period may not exceed one year unless the Governor makes an additional adjustment pursuant to subdivision (a).

(c) Nothing in this section affects the powers and duties established in the California Emergency Services Act (Chapter 7 (commencing with Section 8550) of Division 1 of Title 2 of the Government Code).

(d) The Governor shall, within 10 days of invoking subdivision (a), provide written notification to the Legislature of the action undertaken.

SEC. 2 No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

TITLE 13. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER PROPOSED AMENDMENTS TO THE ZERO EMISSION BUS REGULATION

The Air Resources Board (the Board or ARB) will conduct a public hearing at the time and place noted below to consider adoption of amendments to the California Zero Emission Bus (ZBus) Regulation. The proposed amendments would postpone the purchase requirement for zero emission buses by three years for transit agencies on the diesel path, and one to two years for those agencies on the alternative fuel path. A requirement for an advanced demonstration project is proposed to offset some of the emission losses resulting from the postponement.

DATE:	October 19, 2006
TIME:	9:00 a.m.
PLACE:	California Environmental Protection Agency Byron Sher Auditorium 1001 I Street Sacramento, California 95814

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., October 19, 2006, and may continue at 8:30 a.m., October 20, 2006. This item may not be considered until October 20, 2006. Please consult the agenda for the meeting, which will be available at least 10 days before October 19, 2006, to determine the day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at 916-323-4916 by voice or through the California Relay Services at 711, to place your request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at 916-323-7053.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed amendments to title 13, California Code of Regulations, sections 2023.1 (Fleet Rule for Transit Agencies – Urban Bus Requirements), Transit Fleet Requirements), 2023.3 (Fleet Rule for Transit Agencies – Zero-Emission Bus Requirements), and 2023.4 (Reporting Requirements for Transit Agencies).

Background: In February 2000, the Board confirmed its continued commitment toward improving emissions from public transportation by establishing a new fleet rule for transit agencies and more stringent emission standards for new urban bus engines and vehicles. Under the fleet rule, each transit agency was required to select a compliance

path – either the "diesel" path or the "alternative fuel" path. The regulations also included requirements regarding ZBuses, with the goal of developing zero emission transit fleets. Zero emission technologies include battery electric buses, electric trolley buses with overhead twin wire power supply, and hydrogen fuel cell buses. A zero emission bus is defined as producing zero exhaust emissions of any criteria or precursor pollutant under any and all possible operational modes and climates. The ZBus regulation consisted of two primary elements for large transit agencies – requirements that diesel path agencies initiate a ZBus Demonstration Project and a requirement that a minimum percentage of buses purchased or leased be ZBuses starting in the 2008 model year.

Under the initial regulation, transit agencies that were on the diesel path and had more than 200 urban transit buses on January 31, 2001, were required to implement a ZBus Demonstration Project. As many as three agencies could team up to share costs and resources. The buses were to begin revenue service no later than July 1, 2003, and remain in revenue service for a minimum duration of 12 calendar months. The agencies would then submit a written report on the demonstration project to the ARB's Executive Officer no later than January 31, 2005. Five transit agencies met the criteria for having to implement a ZBus Demonstration Project.

Progress on the initial demonstration projects was mixed. Four of the five agencies selected fuel cell powered buses as the technology most likely to cost-effectively meet the required performance standards and emission requirements in the long term. At the time the regulation was developed, information available to staff indicated that fuel cells would be deployed in buses before light-duty vehicles. This was due to the buses' ability to handle larger size and weight fuel cells. As it turned out, fuel cell and vehicle manufacturers switched their focus towards developing light-duty fuel cell applications.

In June 2004, the staff brought proposed amendments to the demonstration project requirements to the Board. After reviewing the status of technology and meeting with bus manufacturers and transit agencies, staff concluded that an adequate number of fuel cell buses were not available. The Board amended the demonstration project requirements by reducing the number of buses required to three per demonstration project, instead of three per transit agency. This brought the cost of the demonstration project back to that projected in the original rulemaking. The Board also delayed the date the demonstration project buses were to be in operation to the end of February 2006.

The originally-adopted purchase requirements remain in effect. Large transit agencies (those with more than 200 buses) on either fuel path are required to implement the ZBus purchase component of the program. For transit agencies on the diesel fuel path, a minimum 15 percent of purchase and lease agreements, when aggregated annually, for 2008 through 2015 model year urban buses must be ZBuses. For transit agencies on the alternative fuel path, the 15 percent ZBus acquisition requirement starts with model year 2010 and runs through model year 2015. Transit agencies on the diesel path must submit a compliance plan by January 2007 and transit agencies on the

alternative fuel path must submit a compliance plan by January 2009. A transit agency introducing a ZBus earlier than required will earn credits that may be used in meeting the overall acquisition requirements.

The Proposed Amendments: As the date for implementation of the purchase requirement for the ZBus regulation approaches, staff's assessment of technology readiness and the cost of implementation indicates that further amendments of the regulation are necessary. The proposed amendments include a delay of the ZBus purchase requirement and addition of an Advanced Demonstration Project element. They also revise other regulatory provisions to conform with and clarify the proposed amendments.

Staff is proposing that the start of the purchase requirement be postponed by three years for transit agencies on the diesel path, so that it would start with the 2011 model year. For transit agencies on the alternative fuel path, the delay would be one or two years – to the 2011 or 2012 model years – with the two-year delay applicable to alternative fuel path transit agencies choosing to participate in the Advanced Demonstration Program requirement described below. Since the purchase requirement will be delayed, staff proposes that the purchase requirement be extended through model year 2026 for transit agencies in either fuel path.

To provide performance goals and production targets for manufacturers and confidence to transit agencies, staff is proposing a provision under which no later than June 30, 2009, the Executive Officer is to evaluate the purchase cost, the fuel cell durability or warranty and reliability. The Executive Officer would be directed to reduce the percentage purchase requirement for a specified model year if specified criteria are not met. The Executive Officer would repeat this process annually.

To ensure continued development of ZBus technology and offset some of the emission losses, staff is proposing a new Advanced Demonstration Project element. Participation would be mandatory for transit agencies on the diesel path and optional for those on the alternative path. The start date of the Advanced Demonstration Project would depend on the fueling path of the transit agency: diesel path agencies to start January 1, 2009, and the alternative fuel path agencies to begin on January 1, 2010. The Advanced Demonstration Project would provide valuable information on the integration of zero emission buses within the regular fleet.

A single transit agency conducting an Advanced Demonstration Project would have to purchase a minimum of six ZBuses, which would need to be in revenue service as of January 1, 2009. An alternative fuel path transit agency could meet up to half of its ZBus minimum with near zero emission buses at a 3 to 1 ratio. Instead of a single transit agency program, agencies may join together to conduct a multi-transit agency Advanced Demonstration Project. The multi-transit agency demonstration requires a minimum of twelve buses overall, with each agency purchasing a minimum of three ZBuses. For example, a demonstration with five transit agencies participating would require 15 ZBuses, since each transit agency needs to purchase a minimum of three

buses. The near zero emission mechanism would be available for alternative fuel path transit agencies.

COMPARABLE FEDERAL REGULATIONS

Currently there are no federal emission standards or requirements for zero-emission or near zero emission buses.

AVAILABILITY OF DOCUMENTS AND CONTACT PERSONS

The Board staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulation, which includes a summary of the economic and environmental impacts of the proposal. The ISOR is entitled: "Staff Report: Initial Statement of Reasons: Proposed Amendments to the Zero Emission Bus Regulation."

Copies of the ISOR and the full text of the proposed regulatory language, in underline and strikeout format to allow for comparison with the existing regulations, may be accessed on the ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, California 95814, or by calling (916) 322-2990 at least 45 days prior to the scheduled hearing October 19, 2006.

Upon its completion after the Board hearing, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on the ARB's website listed below.

Inquiries concerning the substance of the proposed regulation may be directed to Ms. Lesley Crowell, Air Pollution Engineer, by email at lcrowell@arb.ca.gov, or by phone at (916) 323-2913, or to Mr. Gerhard Achtelik, Manager, ZEV Infrastructure Section, by email at gachteli@arb.ca.gov or by phone at (916) 323-8973.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Ms. Artavia Edwards, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-6070, or Ms. Alexa Malik, Regulations Coordinator, at (916) 322-4011. The Board has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on the ARB Internet site for this rulemaking at www.arb.ca.gov/regact/zbus06/zbus06.htm.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulations are presented below.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action will not create costs or savings to any state agency or in federal funding to the state, costs or mandate to any school district whether or not reimbursable by the state pursuant to Part 7 (commencing with section 17500), Division 4, Title 2 of the Government Code, or other nondiscretionary savings to state agencies. The regulatory proposal directly impacts local agencies that operate transit fleets with more than 200 urban buses. Staff projects an estimated combined cost savings to these transit agencies of approximately $59 million over the four year period beginning January 2008. Extension of the purchase requirement to cover 2016-2026 is expected to result in a combined cost increase to transit agencies of approximately $32-58 million annually over that 11 year period, relative to no zero emission buses being purchased, but cost estimates that far in the future are necessarily speculative. The cost estimates are not indicative of the actual direct cost to transit agencies because the agencies typically receive federal and regional funds for the acquisition of buses and implementing alternative fuel infrastructure.

In developing this regulatory proposal, the ARB staff evaluated the potential economic impacts on representative private persons or businesses. Any business involved in the production or use of zero emission buses potentially would be indirectly affected by the proposed amendments. Those potentially affected are manufacturers that supply components for fuel cells, batteries, integration systems, chassis, and distributors and retailers that sell such equipment. Most of these manufacturers are located outside of California. The regulation directly impacts transit agencies that operate 200 or more urban buses.

The Executive Officer has made an initial determination that the proposed regulatory action will not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons.

In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action will not affect the creation or elimination of jobs within the State of California; the creation of new businesses or elimination of existing businesses within the State of California; or the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the ISOR.

The Executive Officer has also determined, pursuant to title 1, CCR, section 4, that the proposed regulatory action will not affect small businesses because the modifications are discretionary and do not affect any small businesses.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer finds that the reporting requirements of the regulation that apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board or that has otherwise been identified and brought to the attention of the Board would be more effective in carrying out the purpose for which the action is proposed or would be as effective and less burdensome to affected private persons than the proposed action.

SUBMITTAL OF COMMENTS

The public may present comments relating to this matter orally or in writing at the hearing, and in writing or by email before the hearing. To be considered by the Board, written submissions not physically submitted at the hearing must be received **no later than 12:00 noon, October 18, 2006**, and addressed as follows:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal : http://www.arb.ca.gov/lispub/comm/bclist.php

Facsimile submittal: (916) 322-3928

The Board requests, but does not require that 30 copies of any written statement be submitted and that all written statements be filed at least 10 days prior to the hearing so that ARB staff and Board Members have time to fully consider each comment. The Board encourages members of the public to bring to the attention of staff, in advance of the hearing, any suggestions for modification of the proposed regulatory action.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under that authority granted in Health and Safety Code sections 39600, 39601, 39659, 39667, 43013, 43018, 43100, 43101, 43104, and 43806. This action is proposed to implement, interpret and make specific sections 39002, 39003, 39017, 39018, 39033, 39500, 39650, 39667, 39700, 39701, 40000, 41510, 43000, 43000.5, 43009, 43013, 43018, 43102, 43701(b), 43801, 43806 of the Health and Safety Code, and section 233 and 28114 of the Vehicle Code.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, Title 2, Division 3, Part 1, Chapter 3.5 (commencing with section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non-substantial or grammatical modifications. The Board may also approve the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action; in such event the full regulatory text, with the modifications clearly indicated, will be made available to the public, for written comment, at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from the ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, California 95814, (916) 322-2990.

CALIFORNIA AIR RESOURCES BOARD

Michael R. Scheible

for Catherine Witherspoon
Executive Officer

Date: August 22, 2006

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS

PROPOSED AMENDMENTS TO THE ZERO EMISSION BUS REGULATIONS

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does the mention of trade names or commercial products constitute endorsement or recommendation for use.

Date Published:	September 1, 2006
Scheduled for Consideration:	October 19-20, 2006

Prepared By:

Zero Emission Vehicle Infrastructure Section
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Acknowledgements:

Staff appreciates the time and assistance provided by bus, fuel cell, and integration manufacturers, as well as, transit agencies, and environmental groups.

Staff also wishes to acknowledge the support and work from Kathy Jaw and Nicole Dolney, under the direction of Todd Sax, Manager, Regulatory Support Section, Planning and Technical Support Division

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I EXECUTIVE SUMMARY

Air quality in California has improved dramatically over the past 30 years, due in large part to the continued progress in controlling pollution from mobile sources. Despite the achievements to date, the vast majority of Californians live in areas of the state that still do not meet State or federal health-based ambient air quality standards.

In February 2000 the Board confirmed its continued commitment toward improving emissions from public transportation by establishing a new fleet rule for transit agencies and more stringent emission standards for new urban bus engines and vehicles. The rule also promoted advanced technologies by adopting zero emission bus (ZBus) demonstration and ZBus acquisition requirements for larger transit agencies[1]. The focus of this proposal is the ZBus section of the regulation.

Based on demonstrated performance, expected cost and availability, transit agencies viewed the fuel cell engine as the transportation industry's environmental solution and eagerly initiated efforts to further test and evaluate fuel cell buses. In addition, at the time the transit bus regulation was developed, information available to staff indicated that the research and development of fuel cells would result in their market application in transit buses before their application in light duty vehicles. However, that has changed, and more recently manufacturers have focused their efforts primarily on developing light duty vehicle fuel cell applications instead of bus applications.

In June 2004, staff brought amendments to the ZBus requirement to the Board. Staff proposed amendments to the ZBus program to conform to the market conditions and availability of ZBuses. The Board revised the zero emission bus demonstration program by reducing the number of concurrent fuel cell buses and extending the time period for initiation and completion of the demonstration projects[2]. Despite the efforts of the technology providers and transit agencies, ZBus technology has not developed as rapidly as initially projected and staff proposes additional amendments.

A Proposed Requirements

In February 2000, the Board established a new fleet rule for transit agencies which included the zero emission bus (ZBus) regulation. Each transit agency was required to select a compliance path – either the "diesel" path or the "alternative fuel" path. The path selection set the fuel type for new urban bus acquisitions through model year 2015. Transit agencies, on either path, were required to achieve fleet reduction requirements for emissions. The zero emission bus portion of the rule promoted advanced technologies by requiring a demonstration and a fifteen percent acquisition or purchase requirement[1]. The diesel path agencies were required to conduct the initial ZBus demonstrations with acquisition requirements starting in 2008. Since the alternative fuel path required new infrastructure, such as high pressure natural gas tanks, alternative fuel path transit agencies were exempt from the initial demonstration. In addition, the

[1] ARB. February 24, 2000. Resolution 00-2.
[2] ARB. June 24, 2004. Resolution 04-19.

purchase requirement commenced in 2010, a two year delay from those transit agencies on the diesel path.

Staff is proposing that the fifteen percent purchase requirement be postponed by three years for transit agencies on the diesel path, and one to two years for transit agencies on the alternative fuel path. To ensure continued development of ZBus technology and offset some of the emission losses, staff is proposing an Advanced Demonstration requirement. The start date of the Advanced Demonstration depends on the fueling path of the transit agency: diesel path agencies would start January 1, 2009 and the alternative fuel path agencies would begin on January 1, 2010. Staff proposes that the Advanced Demonstration be optional for those transit agencies on the alternative fuel path. All diesel path agencies and those alternative fuel path transit agencies not participating in the Advanced Demonstration would start the purchase requirement on January 1, 2011. Alternative fuel path transit agencies that opt into the Advanced Demonstration would be given an additional year, January 1, 2012, for the start of the purchase requirement.

Staff believes the Advanced Demonstration will provide valuable information on the integration of zero emission buses within the regular fleet. The purpose of the advanced demonstration is to give the transit agencies' maintenance personnel and operators experience with a larger fleet of zero emission buses, and allow the transit agencies to develop or expand experience with hydrogen. Since the purchase requirement will be delayed in all scenarios, staff proposes to extend the purchase requirement from 2015 to model year 2026.

An Advanced Demonstration by a single transit agency would require purchase and demonstration of a minimum of six ZBuses. Or, several agencies may join together to form a multi-transit agency Advanced Demonstration. The multi-transit agency demonstration requires a minimum of twelve buses overall, with each agency purchasing a minimum of three ZBuses. For example, a demonstration with five transit agencies participating would require 15 ZBuses since each transit agency needs to purchase a minimum of three buses.

B Environmental and Economic Impacts

The proposed amendments will delay emission reductions in the 2015 time frame as presented on Table I-1. These emission estimates are based on Scenario 1, where the purchase requirement is delayed until 2011 and alternative fuel path transit agencies opt to not participate in the Advanced Demonstration and align their purchase requirements with the diesel path transit agencies in 2011. There is no way to recoup these reductions since ZBuses represent the cleanest available technology and there is no substitute technology that achieves the same benefit.

Table I-1: Impacts on Emissions from Proposed Regulation through 2015 (Tons Per Year)

	Oxides of Nitrogen (NOx)	Particulate Matter (PM)	Carbon Monoxide (CO)	Hydrocarbons (HC)
2010	(2.15)	(0.081)	(2.21)	(0.053)
2015	(2.21)	(0.084)	(2.29)	(0.055)

The existing regulation is expensive and, if not amended, would severely impact transit agency operations and their ability to adequately serve the public. The current cost of the hydrogen fuel cell buses is estimated to be about $2.25 million per bus[3].
To meet the 15 percent purchase requirement imposed by the existing regulation in 2008, transit agencies would be paying over five times the cost of a conventional bus. Bus cost estimates are not indicative of the actual direct cost to transit agencies. Transit agencies typically receive federal and regional funds for the acquisition of buses and implementing alternative fuel infrastructure. The Federal Transit Administration funds 80-percent of the cost of a diesel bus and 90-percent of the incremental cost of an alternatively fueled bus. However, federal funds are limited and the current cost of available technology makes successful implementation of the existing regulation infeasible.

Since transit agencies have a fixed budget to work with, compliance with the existing regulation may cause them to reduce the total number of buses purchased to afford the fuel cell buses. Reducing the total number of new buses purchased means leaving older and dirtier buses on the road longer or a reducing transit service due to the fleet reduction.

By delaying the 15 percent purchase requirement, staff estimates that the revisions will result in a total cost savings of $59 million to the transit agencies, state agencies, and federal government from 2008 through 2011. After 201, the estimated cost for all transit agencies affected by the proposed regulation, of acquiring zero emission buses, is about $32 - $58 million per year. Conversely, the proposed regulatory changes may have a negative fiscal impact on fuel cell manufacturers because they will delay their return on investment.

Based on costs presented by fuel cell, chassis, system integrators and transit operators, staff determined that, at least for the early years of the program, the dollars spent per ton of pollutant reduced under the ZBus program will be much higher than for typical ARB regulatory measures. However, these costs will decrease as the production volume increases. With production volumes at around 100 buses, the cost of the next

[3] Michael Tosca, Senior Product Manager, Fleet Products, UTC Fuel Cells. 08/08/06

generation fuel cell bus is estimated to be around $1 million[4]. From these costs staff has calculated cost effectiveness to be about $380 per pound of oxides of nitrogen reduced. Staff anticipates the actual cost per pound to be lower, since this cost does not include life-cycle cost savings. This value also does not include funding received from any government funding sources, such as the Federal Transit Administration.

Although the initial purchase costs may still be higher than conventional diesel and alternative fuel bus technology, the price is comparable to an electric trolley bus. Also, as technology is optimized, fuel cell bus operation and maintenance costs are estimated to be in line with electric trolley buses, and significantly lower than diesel and alternative fuel buses. When incorporating these factors along with additional improvements to fuel cell technology, staff anticipates that life cycle costs will decrease the cost per pound of emission reduced. This regulation provides a necessary avenue to bring this technology to the market. In addition, the Board has confirmed in previous regulatory decisions, zero emission vehicle programs are an essential component of the State's long-term air-quality strategy.

C Regulatory Authority

The proposed amendments, as described herein, are consistent with the authority of the ARB to control emissions from mobile sources. To maintain current emission reduction goals set for transit buses in 2000[1], the ARB staff recommends that the Board adopt the proposed amendments to sections 2023.1, 2023.3 and 2023.4, title 13, California Code of Regulations, set forth in the proposed Regulation Order in Appendix A.

D Staff Recommendation

The ARB staff recommends that the Board adopt the amendments as set forth in the proposed Regulation Order in Appendix A and as described in this Initial Statement of Reasons.

[4] Michael Tosca, Senior Product Manager, Fleet Products, UTC Fuel Cells. "H2 Fuel Cell Buses For California". Presented to ARB Staff during 06/21/06 workshop meeting.

II INTRODUCTION

The goal of the Air Resources Board (ARB or "the Board") is to provide clean, healthful air to the citizens of California. California's commitment to providing clean public transportation is an important part of achieving this goal. Public transportation has important societal benefits, including providing access to work and education, reducing traffic congestion, and meeting the mobility needs of the public, including the elderly and physically challenged.

Most types of public transportation, however, are also sources of engine exhaust emissions of oxides of nitrogen (NOx) and hydrocarbons (HC) which contribute to the atmospheric formation of ozone and fine particulate matter (PM). Diesel PM is identified as a toxic air contaminant – a cancer-causing pollutant that also has significant short- and long-term negative respiratory and cardiovascular impacts. These emissions often occur within California's most populated areas. It is, therefore, vital to all Californians that the ARB continue its efforts to reduce engine exhaust emissions from all sources, including transit buses, which are the subject of this rulemaking.

In February 2000, the Board confirmed its continued commitment toward improving emissions from public transportation by establishing a new fleet rule for transit agencies which included the zero emission bus (ZBus) regulation. Each transit agency was required to select a compliance path – either the "diesel" path or the "alternative fuel" path – by January 1, 2001. Path selection set the fuel type for new urban bus acquisitions through model year 2015. Transit agencies, on either path, were required to achieve fleet reduction requirements for NOx and PM emissions. The zero emission bus portion of the rule promoted advanced technologies by adopting ZBus demonstrations, applicable to diesel path agencies, and ZBus acquisition requirements applicable to transit agencies on both fuel paths[1].

Recognizing the long term nature of the regulations, the Board required staff to report back regularly on implementation progress. Staff worked closely with transit agencies to encourage compliance and reported back to the Board at its September 20, 2001, and March 21, 2002, public meetings. ARB staff had closely monitored activities related to ZBus demonstrations and it was clear that while demonstrations were significantly behind schedule, the delay was a consequence of conditions out of the transit agencies' control. As instructed by the Board, staff brought amendments to the ZBus rule to the Board, which were adopted at the June 24, 2004, public hearing[2]. These amendments to the ZBus program were made to conform to market conditions and the availability of ZBuses. The amendments to the ZBus program were necessary and appropriate.

Staff is bringing this proposal to the Board to make additional amendments to the ZBus sections of the Fleet Rule for Transit Agencies.

Regulatory Authority

The ZBus requirements are an integral part of California's mobile source control efforts, and are intended to encourage the development of advanced technologies that will secure increasing air quality benefits for all Californians, particularly the majority of Californians who live in areas where the federal and State ambient standards for ozone are exceeded. The proposed amendments address the current state and availability of ZBus technology, and reduce the overall cost of compliance to the transit agencies while maintaining the push towards ZBus commercialization.

ARB has been granted the authority to regulate emissions through Health and Safety Code 43013 and 43018. These sections direct the ARB to adopt emission standards to reduce emissions from new motor vehicles, including urban transit buses, and achieve air quality attainment goals. They direct the ARB to assure that its motor vehicle emission standards are cost-effective, and the ARB endeavors to provide maximum flexibility.

Applicability

The Fleet Rule for Transit Agencies regulates transit fleet vehicles that are owned or leased by public transit agencies, including transit buses that meet the definition of an urban bus. The Zero Emission Bus (ZBus) portion of the regulation applies to those fleets that have more than 200 urban buses.

An urban bus is a passenger-carrying vehicle that is powered by a heavy heavy-duty diesel engine (33,000 Gross Vehicle Weight), with a load capacity of fifteen or more passengers and intended primarily for intra-city operation. These buses are generally 35 feet in length or longer. Urban bus operation is characterized by short rides and frequent stops. To facilitate this type of operation, more than one set of quick operating entrance and exit doors would normally be installed. Since fares are usually paid in cash or token, rather than purchased in advanced in the form of tickets, urban buses would normally have equipment installed for the collection of fares. Urban buses usually operate on a fixed route consisting of stops and starts as passengers are routinely picked up and delivered to their destinations. Urban buses are also typically characterized by the absence of equipment and facilities for long distance travel, e.g., restrooms, large luggage compartments, and facilities for stowing carry-on luggage[5]. Implementation timelines for ZBuses are set by the fuel path that the agencies have chosen to follow: Diesel or Alternative Fuel.

[5] ARB. February 24, 2005. Final Regulation Order: Modifications To The Fleet Rule For Transit Agencies And New Requirements For Transit Fleet Vehicles

III BACKGROUND

California's regulations applicable to transit agencies and the manufacturers of urban bus engines and vehicles are innovative and go beyond the federal requirements for urban buses. Since rule adoption, many transit agencies have installed natural gas refueling infrastructure and purchased alternative-fuel urban buses; re-powered diesel engines to cleaner exhaust emission standards; installed particulate filters on diesel engines and experimented with developing technologies, such as Diesel Hybrid Electric Buses (DHEB) and cleaner fuels. Many of California's transit agencies consider themselves to be innovators and incubators for advanced technologies.

The Board adopted the ZBus requirements (Title 13, CCR, Section 1956.3, recently moved to section 2023.3) in 2000 as part of the comprehensive fleet rule for transit agencies within California[1]. The development of zero emission transportation is key to California's long-term clean air strategy and the ZBus regulation establishes demonstration and acquisition criteria for large transit agencies to further that goal. Zero emission technologies include battery electric buses, electric trolley buses with over-head twin-wire power supply, and fuel cell electric buses. A "zero emission bus" is defined as producing zero exhaust emissions of any criteria or precursor pollutant under any and all possible operational modes and climates. "Criteria pollutants" are those for which the ARB has adopted ambient air quality standards[5].

In addition to reducing the public's exposure to smog forming emissions the transit bus regulation aimed to reduce toxic air contaminants and be technology forcing by requiring zero emission engines.

A ZBus Initial Demonstration Requirements

Any transit agency on the diesel path that had more than 200 urban buses as of January 31, 2001, was required to implement a ZBus demonstration project. Up to three transit agencies could participate in any one joint project, provided the project did not utilize electric trolley buses. Originally, the key components and milestones of the demonstration project were as follows:

- Transit agencies were to prepare bid proposals for materials and services necessary to implement the demonstration project no later than January 1, 2002.
- The required ZBuses were to be in revenue service no later than July 1, 2003.
- Transit agencies were to place at least three ZBuses in revenue service per participating agency, but up to three transit agencies in an air basin could petition to implement a joint demonstration project.
- The buses must be in revenue service for a minimum duration of 12 calendar months.
- Transit agencies were to submit a report on the demonstration project to the ARB's Executive Officer no later than January 31, 2005.
- The ARB was to review ZBus technology and the feasibility of implementing the purchase provision of the program (described below) no later than January 2006.

B Transit Agencies in the Initial Demonstration

In 2001 there were 71 transit agencies reporting to the ARB, 44 of which were on the diesel path. Of these, only five transit agencies met the criteria for having to implement a ZBus demonstration project (Table III-1).

Table III-1: ZBus Demonstration Transit Agencies

Transit Agencies Required to Implement ZBus Demonstration Project
Alameda/Contra Costa Transit District
Golden Gate Bridge Highway and Transportation District
San Francisco Municipal Railway
San Mateo County Transit District
Santa Clara Valley Transportation Authority

Of the five eligible transit agencies, four are participating in fuel cell bus demonstrations and the fifth, San Francisco Municipal Railway, is using its electric trolley fleet to meet the ZBus demonstration requirements. The four transit agencies formed two partnerships, with Alameda/Contra Costa Transit District (AC Transit) being joined by Golden Gate Bridge Highway and Transportation District (GGT), and Santa Clara Valley Transportation Authority (VTA) being joined by San Mateo County Transit District (SamTrans). In addition, SunLine Transit Agency joined the AC Transit and GGT partnership voluntarily and purchased one bus; the number of buses operated by SunLine does not require their participation in a ZBus demonstration.

AC Transit, GGT and SunLine are demonstrating four Van Hool transit buses equipped with United Technology Corporation (UTC) fuel cells and Nickel sodium chloride (ZEBRA) batteries in a hybrid configuration. AC Transit and GGT jointly operate buses in the Oakland area while SunLine operates a single bus in and around Thousand Palms. VTA and SamTrans are operating three Gillig Corporation transit buses equipped with Ballard fuel cells in the San Jose area.

C Progress on the Initial Demonstration

The transit agencies selected fuel cell powered buses as the technology most likely to cost-effectively meet the required performance standards and emission requirements in the long term. As the ZBus regulation was being developed, fuel cell technology had demonstrated greater potential to meet transit agencies' power, range, and refueling requirements than battery electric zero emission buses and offered greater route flexibility and focused infrastructure needs when compared to over-head wire trolley buses. Already, buses equipped with direct hydrogen, proton exchange membrane (PEM) fuel cells or with, on-board methanol reforming, phosphoric acid fuel cells had been demonstrated successfully. In addition, fuel cell manufacturers anticipated being production ready by 2003.

Information available indicated that the research and development of fuel cells in transit buses would lead to their deployment in transit buses before their application in light duty vehicles[6]. Buses are better suited to handle the relatively larger size and weight of fuel cells and on-board fuel storage. The deployment of fuel cells in a controlled fleet application would allow fueling and service requirements to be performed at a single facility, thereby helping to mediate infrastructure and support issues in the early years. As it turns out, fuel cell and vehicle manufacturers switched focus then towards developing light duty vehicle fuel cell applications. As a result, fuel cell bus engines have not yet reached commercialization.

The transit agencies demonstrated due diligence in attempting to comply with the demonstration requirements. For example, AC Transit and VTA, the lead transit agencies of the two ZBus demonstrations, individually initiated efforts to develop ZBus programs as the ZBus regulation was being promulgated. Transit agencies solicited bids for the purchase of FCBs with sufficient lead time to meet regulatory requirements. However, transit agencies experienced difficulties in receiving responses from fuel cell and bus manufacturers. Despite the exemplary efforts, the FCBs could not be delivered in time to allow the demonstration to be completed prior to January 2005. The FCBs for the VTA demonstration were not received until second quarter 2004 and the FCBs for AC Transit were not received until fourth quarter 2005. As a result, the in-revenue demonstrations of the FCBs started over one year after the originally required start date.

In addition, the cost of buses was greater than anticipated. During the development of the original rulemaking, in 1999, ARB estimated that by 2001 the cost for a demonstration FCB would be just in excess of $1 million and by 2003/2004 a FCB would be around $550,000 to $790,000, or cost competitive with electric trolley buses by the time the ZBus purchase requirements started[6]. However, the cost of a FCB for the initial demonstration was greater than $3 million[7]. By soliciting partners, the lead transit agencies were able to secure additional funding to allow the demonstrations to go forward despite the increases in cost.

In June 2004, staff presented an update on the demonstration projects and proposed amendments to the Board. After reviewing the status of technology, cost and bus availability, the Board recognized the need to revise the number of concurrent, in-use fuel cell buses that must be demonstrated, and delayed the start of the demonstration projects until the end of February 2006[2]. The state of technology, delay in the availability of fuel cell buses to California, and the data from European fuel cell buses justified reducing the number of buses required in California to three per demonstration project, instead of three per transit agency. This brought the costs of the demonstration project back to that projected in the original rulemaking[8].

[6] ARB. December 10,1999. Staff Report: Initial Statement of Reasons: Proposed Regulation for a Public Transit Bus Fleet Rule and Emission Standards for New Urban Buses
[7] NREL VTA Evaluation Report, 02/06
[8] ARB. May 7, 2004. Staff Report: Initial Statement of Reasons. Proposed modifications to the exhaust emission standards and test engines and vehicles, the fleet rule for transit agencies, and zero-emission bus requirements.

D Existing ZBus Purchase Requirements

The originally-adopted purchase requirements remain in effect. Large transit agencies (those with more than 200 buses) on either fuel path are required to implement the ZBus purchase component of the program. For transit agencies on the diesel fuel path, a 15 percent aggregate total of all bus acquisitions from model year 2008 through model year 2015 must be ZBuses. For transit agencies on the alternative fuel path, the 15 percent ZBus acquisition requirement starts with model year 2010 and runs through model year 2015. Transit agencies on the diesel path must submit a compliance plan by January 2007 and transit agencies on the alternative fuel path must submit a compliance plan by January 2009. Any request for deviation from the ZBus purchase requirement must be submitted to, and approved by, the Executive Officer prior to the transit agency's submittal of the purchase order.

IV Technology Development Activities

While fuel cell bus technology has not develop as quickly as anticipated and there appeared to be a decrease in fuel cell bus related activities initially, the activities described below indicate a growing interest by various fuel cell and bus providers as well as the transit agencies world wide seeking to deploy fuel cell buses.

Fuel Cell Bus Programs[9]

California is not alone in promoting and demonstrating fuel cell buses. Internationally, over 50 hydrogen fuel cell and hybrid hydrogen fuel cell buses have already completed or are currently involved in at least 10 different demonstration projects. CUTE (Clean Urban Transport for Europe) placed 3 hybrid fuel cell urban buses using Citaro chassis and Ballard fuel cells in 9 different European cities for two year demonstration programs. The same bus and fuel cell system was deployed in additional programs in Reyjavik, Iceland and Perth, Australia. These projects were so successful that many of these cities are looking into extending demonstration times. Additionally, in Japan, Toyota and Hino are demonstrating a fuel cell bus in airport to city transport service and Hyundai held trial operation of fuel cell buses during this year's World Cup. In addition, over 220 hydrogen fuel cell buses have been proposed for the next five years under separate programs. Shanghai, China and San Paulo, Brazil are currently in testing stages of the United Nations Development Program Global Environment Facility's fuel cell bus demonstration program. The Natural Resources Canada Fuel Cell Program has plans for over 20 buses to be in demonstration by 2009 in Whistler, Canada. Upcoming Olympic Games have inspired city officials in Beijing, Vancouver, and London to call for large scale hydrogen fuel cell bus demonstrations.

Domestically, 12 buses under 3 different demonstration programs have been or are currently being completed. Throughout the United States, fuel cell bus demonstrations have already been completed in Santa Clara, California, under the California Fuel Cell Partnership program, and Washington D.C., under the Federal Transit Administration (FTA) funded Georgetown Fuel Cell Bus Program. The Georgetown Fuel Cell Bus Program allows testing and research at the University of California, Davis and the University of Northern Florida in Jacksonville on two separate transit buses manufactured by Bus Manufacturing USA, Incorporated and fitted with Fuji fuel cell stacks. In Honolulu, Hawaii one hybrid fuel cell bus is currently in service on Hickam Airbase as a flight crew transportation vehicle. Future projects funded by the FTA Automotive Based Fuel Cell Hybrid Bus program are planned in Alabama, Delaware, and Connecticut. Under the Greater Columbia Fuel Cell Challenge, the University of South Carolina and the City of Columbia have also been encouraged to engage in hydrogen fuel cell bus demonstrations.

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[9] ARB. "Summary of Demonstration Projects" (http://www.arb.ca.gov/msprog/bus/zeb/fcbdemos.pdf) 07/10/06

In addition, the United States Department of Transportation (U.S. DOT) has been allotted $49 million over four years for the advancement of fuel cell transit buses. This U.S. DOT program requires 50 percent match funding from successful proposals. Solicitation for white papers describing potential projects have been made and evaluated. Projects in California have been selected to participate in the final round of consideration. Even if a California program is not selected the U.S. DOT fuel cell bus advancement program assures additional fuel cell bus development activity.

V NEED FOR REGULATORY AMENDMENTS

Zero Emission Bus Demonstration and Purchase Requirements

After reviewing the status of technology and bus availability, staff sees a need to revise the start date of the zero emission bus purchase requirements due to high bus costs, and unproven durability, reliability, and ability of manufacturers to produce the number of buses required by the regulation. To keep the momentum moving forward, encourage fuel cell manufacturers to increase their production numbers, show that integration of a larger zero emission bus fleet is possible, and prove that the costs can be decreased, staff has included an Advanced Demonstration program and a delay in the purchase requirement in the proposed amendments.

While still on-going, the demonstrations at VTA, AC Transit, and SunLine have demonstrated the viability of fuel cell powered transit buses. The buses have been operated on numerous routes and have successfully proven their ability to perform on hilly terrain, on high-speed highways, and in-city stop-and-go applications. The reaction from the public has been positive with riders appreciating the much quieter operating characteristics of the fuel cell powered buses. In addition, the hybrid configured fuel cell buses used by AC Transit and SunLine are demonstrating a fuel efficiency of 7.6 miles per kilogram of hydrogen[4,10]. This nearly doubles the fuel economy compared to diesel buses. However, additional work is necessary to demonstrated reliability and durability concerns. Reliability is typically measured by the miles between propulsion related road calls. For diesel buses this occurs roughly once every 11,000 miles[7]. VTA data shows that propulsion related road calls for their fuel cell buses occurred roughly once every 1000 miles[7]. The AC Transit experience is expected to be much better, but data is not yet available.

Zero emission technology is more expensive compared to conventional transportation technology. San Francisco Municipal operates the largest fleet of electric trolley buses in the United States, with 344 trolleys[11] on 186 miles of infrastructure. In 1997, an electric trolley without infrastructure cost about $800,000[12]. However, it is important to consider that the infrastructure costs associated with electric trolleys, is between $1 and $1.5 million per mile. The cost variability is related to additional electricity generation equipment needed for inclines and route variations. Though the initial costs incurred by the transit agency are significantly higher, decreased operation and maintenance costs, and longer useful life add an incentive to this type of technology. Residents prefer the quieter trolley buses over the diesel buses. In addition, diesel buses had significant operating problems under full passenger load on the hills in San Francisco. Many of these routes were converted to electric trolley bus service since the high startup torque

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[10] Paul Scott. "ZEB and NZEB Program Progress plus...Comments on ZEB Program Plan." Presented at 04/14/06 workshop. http://www.arb.ca.gov/msprog/bus/zeb/meetings/041406/ise41406.pdf

[11] SF Muni, "About Trolley Buses" http://www.sfmuni.com/cms/mms/rider/trolley.htm

[12] City and County of San Francisco. Contract No. 888. Procurement of Articulated & Standard Trolley Coaches: Attachment No. 3 page IV-7, Schedule of Prices. 06/27/97

of an electric motor allowed the trolley buses to handle the hills better than the diesel buses. Staff expects fuel cell buses to behave similarly to electric trolleys.

New and developing technology costs are typically much higher but decrease as the technology progresses. The cost of AC Transit buses, equipped with UTC fuel cells, were $3.2 million each[13]. Just over a year later the same fuel cell bus will be about $2.25 million[3]. While this is a significant reduction without a change in technology, this is still greater than anticipated costs. However, more demonstrations around the world each year are rapidly increasing the number of fuel cells, thus expanding manufacturer's knowledge base. According to UTC, once about 100 fuel cell buses are ordered, the price will drop to about $1 million[4]. Staff anticipates that cost will decrease further and become more inline with other technologies as the volume produced increases and the technology become more mainstream. In view of San Francisco Municipal's success with electric trolleys, a zero emission technology, costing in 1997 nearly $800,000 each[12], staff finds a $1 million purchase price for a fuel cell bus is comparable as a start for the 15 percent purchase requirement. In San Francisco Municipal's comparisons of diesel and electric trolleys, costs associated with either technology are equivalent over a bus's useful life. Staff anticipates the lower operation and maintenance cost associated with electric trolleys will also be applicable to fuel cell buses as the technology advances.

Staff is proposing an Advanced Demonstration and to phase in the 15 percent purchase requirement based on the cost, performance, and reliability of the technology. An Advanced Demonstration will allow transit agencies to gain experience in fleet operation of a new technology while gaining confidence in the technology's ability to deliver the required performance. The Advanced Demonstration will allow transit agencies to form a multi agency partnership that can demonstrate a single, relatively large fleet of buses without individually having to bare the full cost of a large fleet demonstration. The Advanced Demonstration will also allow technology providers to increase production levels, thereby implementing cost reductions, and to demonstrate improved technology performance.

Staff is also proposing to correlate the percent purchase requirement to performance targets. By tying the purchase requirements to the performance of the technology, transit agencies will have greater confidence in the technology's ability to perform as needed. In addition, fuel cell providers will be assured of a return on investment for meeting performance targets. This approach will allow the regulation to be smoothly implemented as the technology becomes market ready without further intermittent amendments.

As evidenced by the fuel cell bus activities underway outside of California, focus seems to have returned to fuel cell applications in buses. Based on comments received from fuel cell manufacturers, Ballard and UTC, it appears that improved fuel cells will become available within the next three years. After considering the number of buses in demonstrations world wide, the cost per bus and the state of the technology staff

[13] Jaimie Levin, Director of Marketing and Communications, AC Transit. 07/17/06

recommends amending the regulation, as described in more detail in Section VII, to add an Advanced Demonstration, delaying the purchase requirement and establishing performance targets for the implementation of the purchase requirement.

VI PUBLIC OUTREACH AND ENVIRONMENTAL JUSTICE

The ARB is committed to ensuring that all California communities have clean, healthful air by addressing not only the regional smog that hangs over our cities but also the more localized toxic air pollution that is generated within our communities. The ARB works to ensure that all individuals in California, especially children and the elderly, can live, work and play in a healthful environment that is free from harmful exposure to air pollution.

A. Environmental Justice

On December 13, 2001, the Board approved Environmental Justice Policies and Actions, which formally established a framework for incorporating environmental justice into the ARB's programs, consistent with the directives of State law and policy[14]. "Environmental Justice" is defined as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies. These policies apply to all communities in California but, environmental justice issues have been raised more in the context of low-income and minority communities because of past land use policies and the accumulative impact of a concentration of emitting facilities in some neighborhoods.

To achieve this goal, the ARB has established a Community Health Program and emphasized community health issues in our existing programs. ARB has published, "The Public Participation Guide to Air Quality Decision Making in California" to use as a basic tool and for information needed to understand and participate in air pollution policy planning, permitting, and regulatory decision making processes[15]. The Environmental Justice Policies are intended to promote the fair treatment of all Californians and cover the full spectrum of ARB activities. Underlying these Policies is a recognition that we need to engage community members in a meaningful way as we carry out our activities. People should have the best possible information about the air they breathe and what is being done to reduce unhealthful air pollution in their communities. The ARB recognizes its obligation to work closely with all stakeholders; communities, environmental and public health organizations, industry, business owners, other agencies, and all other interested parties to successfully implement these policies. Our outreach efforts, described below, facilitate this objective.

B. Outreach Efforts

The ARB strives to involve the widest number of affected persons in the development of its regulations. To this end, staff held informal public workshops and meetings prior to publishing the notice and staff report. Information from these workshops can be found through the Zero Emission Bus program website[16]. For this rule, staff conducted four

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[14] Information for these programs can be found at http://www.arb.ca.gov/ch/programs/ej/ejpolicies.pdf.
[15] Information on this program can be found at http://www.arb.ca.gov/ch/public_participation.htm.
[16] More information on ZBus Programs can be found at http://www.arb.ca.gov/msprog/bus/zeb/zeb.htm

public workshops (Table VI-1) and additional focused meetings. Notices for the workshops were posted to ARB's Public Transit Agencies web site and e-mailed to subscribers of ARB's electronic list server. Those workshops held in Sacramento were webcast for individuals who could not travel to the meeting locations. Participation in Southern California workshops was available by telephone conference. To generate additional public participation and to enhance the information flow between ARB and interested persons, staff made all documents, including workshop presentations, available via the Zero Emission Buses web site. In addition, the web site provides background information and serves as a portal to other web sites with related information.

Table VI-1: Workshop Locations and Times

Date	Location
October 27, 2005	Sacramento
January 27, 2006	El Monte
April 14, 2006	Sacramento
June 21, 2006	Diamond Bar

Outreach and public participation are important components of ARB's regulatory development process. In preparing the proposed regulations, ARB staff developed an outreach program to engage Zero Emission Bus equipment manufacturers and distributors, emission control system manufacturers, transit agencies, end-user facility operators, local air pollution control districts, environmental organizations, public health advocates, and other interested parties.

As part of the outreach efforts, ARB staff made extensive personal contacts with industry and facility representatives as well as other affected parties through meetings, telephone calls, and electronic list-serves. These activities included holding [illegible] public workshops, attending 28 industry meetings and conducting more than 30 telephone conversations with working groups, transit agencies, affected manufacturers and other interested stakeholders.

Attendees of the workshops included representatives from environmental organizations, transit agencies, fuel cell manufacturers, bus manufacturers, air pollution control districts, cities and counties, California Natural Gas Association, California Energy Commission, consultants, and other parties interested in transit bus emissions[17].

Staff met with a number of the same stakeholders in focused meetings throughout the rulemaking process to get feedback on staff's proposed regulatory amendments. These stakeholders represent transit agencies, hybrid-electric drive systems, bus manufacturers, natural gas advocates, and environmental organizations. Staff attended and made presentations at the California Transit Association conference in May 2006. Staff also worked closely with ZBus stakeholders, including AC Transit, VTA, SunLine

[17] Sign-in sheets available on ZBus website: www.arb.ca.gov/msprog/bus/zeb/meetings/meetings.htm

Transit, California Energy Commission, National Renewable Energy Laboratory, South Coast Air Quality Management District, Ballard Power Systems (Ballard), ISE, and United Technologies Corporation Fuel Cells (UTC). Alternatives were suggested to the proposed regulation and explored by staff.

VII REGULATORY PROPOSAL

Staff has worked with zero emission bus fuel cell, electric drive system and chassis equipment manufacturers and distributors, end-user facility operators, federal regulatory agencies, environmental groups, and other interested parties since October 2005 to identify approaches that would result in viable implementation for zero emission buses. The most promising options involve adding an Advanced Demonstration and, postponing and extending the purchase requirement. Staff conducted workshops in October 2005, January, April, and June 2006 on these approaches.

Staff recommends that the Board adopt proposed amendments to sections 2023.1, 2023.3, and 2023.4 of title 13, as set forth in Appendix A. All the provisions in the proposed amendments apply to engines and vehicles produced for sale in California. There are three main components to this proposal:

1) Add an Advanced Demonstration for the diesel path and an optional demonstration for the alternative fuel path transit agencies that have a fleet of at least 200 urban buses by January 1, 2007;
2) Amend the ZBus purchase requirement
   - Postpone the start date by 1-3 years, depending on transit agency path and demonstration option
   - Extend the purchase requirement out 15 years from the start date
3) Incorporate an Executive Officer Discretion Clause
   - Allow the Executive Officer to reduce the purchase requirement percentage based on the performance and cost targets achieved
   - Includes an annual review of the performance and cost parameters
   - First analysis of performance and cost parameters to occur 18 months prior to January 1, 2011 purchase requirement.
4) Amend other sections as necessary to conform and clarify, such as
   - Realign the Early Purchase Credits with the new purchase requirement dates.
   - Reporting requirements are extended for Transit agencies with over 150 urban buses.

A Amendments to the Zero emission Bus Rule, title 13, CCR, section 2023.3

1 Advanced Demonstration Requirement

i Single Agency Option

Diesel path transit agencies choosing to conduct a demonstration on their own would be required to purchase at least six zero emission buses. Buses need to be in revenue service as of January 1, 2009.

Alternative fuel path transit agencies may choose to conduct a demonstration on their own provided it involves the purchase of at least six zero emission buses. By participating in an advanced demonstration transit agencies will receive a one year delay in the purchase requirement. In addition, transit agencies will be able to gain expertise in the operation and support of fuel cell buses with a smaller number of buses. All buses need to be in revenue service by January 1, 2010.

ii Zero Emission Enabling Bus Option

The zero emission enabling bus option is in response to comments received during the workshops and is only applicable to alternative path transit agencies during the advanced demonstration. Zero Emission Enabling buses would be required to use a technology that helps to develop zero emission technology. For example, buses that use gaseous hydrogen or gaseous hydrogen blended with natural gas, or a gaseous fuel hybrid configuration, would be considered zero emission bus enabling. Current development in zero emission enabling technology buses has included applications of straight hydrogen and hydrogen blended with natural gas in ICEs. A zero emission enabling bus would need to be certified to the applicable 2010 standard and demonstrate emissions at least 50 percent cleaner than the 2010 standard. All buses utilizing this option need to be in revenue service by January 1, 2010.

The zero emission enabling bus option could allow transit agencies to demonstrate cleaner conventional ICE technology while developing expertise leading to the deployment of ZBuses. The intent of the zero emission enabling bus demonstration option is to foster the development of zero emission bus technology and cleaner lower emitting internal combustion engine (ICE) technology. Only half of the ZBuses required under the demonstration can be replaced. For each ZBus replaced at least three zero emission enabling buses must be purchased.

Depending on the alternative fuel used, transit agencies could deploy hydrogen infrastructure and still use a bus technology similar to buses used in their current operation. For example transit agencies using natural gas fueled ICE buses could operate ICE buses that run on a blend of hydrogen and natural gas. ICE buses operating on straight hydrogen would utilize the same on-board storage systems as fuel cell buses thereby familiarizing transit agencies with higher pressure hydrogen systems, and supporting a transition to ZBuses. The Executive Officer would approve a qualifying zero emission enabling bus demonstration.

iii Multiple Agencies Option

Each diesel path transit agency choosing to participate in a demonstration with other transit agencies is required to purchase at least three zero emission buses, with a minimum combined total of 12 new zero emission buses. While multi-transit agency demonstrations can be conducted with any type of zero emission bus strategy the demonstration cannot be conducted using existing electric trolley systems. All demonstration buses need to be in revenue service as of January 1, 2009.

Each alternative fuel path transit agency choosing to participate in a demonstration with other transit agencies is required to purchase at least three zero emission buses. In addition, the multi-transit agency demonstration needs a minimum of 12 zero emission buses. Alternative fuel path transit agencies can also choose to replace some zero emission buses with zero emission enabling buses provided that less than half of the zero emission buses required under the demonstration are replaced. As previously described, three zero emission enabling buses replace one zero emission bus. Using the zero emission enabling bus option a twelve ZBus demonstration would require the purchase of at least six zero emission buses. The remaining buses can be replaced on a three zero emission enabling buses to a one zero emission bus ratio. All buses need to be in revenue service by January 1, 2010.

2 Purchase Requirement

The start of the purchase requirement for diesel path and alternative fuel path transit agencies would be delayed until January 1, 2011, unless the alternative fuel path transit agency participated in the Advanced Demonstration. The purchase requirement for alternative fuel path transit agencies opting to conduct an Advanced Demonstration would start January 1, 2012. The purchase requirements would run through model year 2026 for either fuel path. Currently, the purchase requirement ends in 2015. The purchase requirements are being extended to help assure one complete fleet turnover has occurred.

3 Performance Based Purchase Requirement

To provide performance goals and production targets for manufacturers and confidence to transit agencies, staff proposes to include a provision under which no later than June 30, 2009, the Executive Officer is to evaluate the purchase cost, fuel cell durability or warranty, and reliability or availability of the ZBus.

Staff proposes that initial costs be compared with electric trolleys, which is also a zero emission technology. It is expected that like electric trolleys, fuel cell buses will have less maintenance than diesel or alternative fuel buses over the life of the bus. Due to this expectation, the life cycle costs for fuel cell buses and electric trolleys are expected to be comparable to conventional buses. In addition, the warranty length/durability and reliability should also be similar to conventional engines. The table below lists the performance guidelines and purchase requirement percentage. The ability of manufacturers to meet the performance goals will be analyzed 18 months prior to the initial purchase requirement and annually thereafter. This determination would start June 30, 2009, and would be reassessed annually by June 30th of each year following until the goals are met. If all goals are met, the 15 percent purchase requirement is fully implemented. If these goals are not met, then the Executive Officer can reduce the purchase requirements according to the guidelines on Table VII-1.

Table VII-1: Performance and Purchase Requirements for ZBuses

	15 percent	8 percent	2 percent
Initial Cost FCB: (Electric Trolley)	1.25:1	1.75:1	3:1
FC Durability or warranty (hrs)	20,000	15,000	3,000
Reliability (miles[18]) or Availability (percent)	10,000 or 80 percent	7,500 or 70 percent	4,000 or 60 percent

Staff compared average warranties, reliability of propulsion systems, life cycle costs, and initial purchase costs of diesel, natural gas, and fuel cell buses. Staff concluded that initial cost, reliability, and fuel cell durability should be monitored and used to determine the appropriate purchase requirement for zero emission buses.

While staff believes that life cycle costs could be a better indicator, staff also believes that this area is still under development and too premature to use as a guide to determine purchase requirements. Due to the limited number of fuel cell buses in operation, insufficient data is available for an accurate life cycle cost analysis. In addition, one life cycle will not have been realized before the regulation would take effect. Information from industry indicates that in the future, operating and maintenance costs for fuel cell hybrid buses will be less than diesel and compressed natural gas (CNG) buses[4,19]. Therefore, staff is using reliability of the propulsion system and durability of the fuel cell as parameters to ensure that the bus operation is at least comparable with conventional engines.

In order for fuel cell buses to be competitive, the durability needs to be similar to conventional urban bus technology, therefore staff proposes as a performance goal durability to be 5 years, 300,000 miles or 20,000 hour for each fuel cell bus propulsion system. The hourly rating was added, since fuel cell bus demonstrations used this as a parameter in their warranty. Thus a 20,000-hour durability would convert to 240,000 to 360,000 miles, with the average speed of a bus depending on the route, ranging from 12 to 18 miles per hour. Since, the technology may not have time to demonstrate this prior to the purchase requirement, staff proposes that the warranty conditions on the fuel cell or propulsion system be considered to determine the status of the technology.

Warranties currently offered for diesel and CNG urban bus engines cover all major propulsion subsystems, minus oil and filter changes as well as less significant parts. John Deere offers a warranty for a CNG urban bus engine that covers three years or 350,000 miles, whichever occurs first[20]. A typical diesel engine warranty runs for five years or 300,000 miles[21]. Warranty costs are usually included into the total engine price. For conventional technologies, extended warranties are also available for an extra cost, at around $2,000 to $4,000 per year[21,22].

[18] Miles between propulsion related road calls.
[19] Jaimie Levin, Director of Marketing and Communications, AC Transit. 7/20/06
[20] Bob Bach, Director of Maintenance, Omnitrans. 7/13/06
[21] Art Douwes, Senior Mechanical Engineer, VTA. 7/14/06
[22] Michael Eaves, President, California Natural Gas Vehicle Coalition. 7/20/06

For the VTA hydrogen fuel cell bus demonstration, Ballard provided a two year, or 1,000 hour warranty[21]. This covered everything pertaining to the fuel cell stack which acted as the propulsion system. UTC offered a two year, 4,000 hour warranty to AC Transit for its hybrid fuel cell bus demonstration program, which also provided full coverage for the fuel cell stack, battery, and other parts associated with the propulsion system[13]. Demonstration warranties are not equivalent to actual service warranties. If the bus were to run 12 hours per day, 365 days a year, total running hours would amount to nearly 4,500 hours each year.

Reliability, expressed as miles between road calls, for diesel, CNG and liquid natural gas (LNG) propulsion systems is fairly well documented by transit agencies. In the VTA demonstration, miles between road calls for diesel propulsion related issues was 11,400, while for fuel cell buses it was about 1000 miles[7]. AC Transit data is expected to be much better due in part to the hybridized fuel cell/battery system; however data is still preliminary and has not been released. Orange County Transportation Authority states that for LNG buses, propulsion related road calls occur every 13,400 miles[23]. While for CNG buses road calls occur between 4,600[24] to 18,500[25] miles. However, it is important to note that how a road call is defined and what failure warrants a road call differs between transit agencies. Some of the variability in road calls is due to this. Staff estimates that propulsion related road calls for diesel or alternative fuel buses using established technology will occur about every 10,000 miles. These numbers are highly dependent upon the operator's and maintenance technician's labor contracts and/or ability to diagnose and prevent future problems through routine maintenance. Therefore, staff estimates that a reliability of 10,000 miles between propulsion related road calls is an appropriate guide for fuel cell buses.

To adjust for this variability, staff is also incorporating the availability of the buses. This parameter includes maintenance and road calls. The reliability and availability parameters will be evaluated jointly and only one parameter will be needed to fulfill the requirements of the Executive Officer Discretion. Availability will be evaluated on a percentage basis. According to the NREL report for VTA availability of diesel buses are approximately 80 percent[7]. Therefore, 80 percent availability will be the basis for which the ZBuses will be compared to for the 15 percent purchase requirement. A minimum of 60 percent availability will be required to meet the 2 percent purchase requirement level.

4 <u>Non-Urban Zero Emission Bus Exemption</u>

Urban buses are defined as vehicles that are powered by a heavy-heavy duty engine, have gross vehicle weight rating of 33,000 pounds, and that carry at least 15 passengers in an urban environment with scheduled stops. Some hybrid system

[23] Ryan Erickson, Maintenance Facility Manager, Orange County Transportation Authority. 7/20/06
[24] Bob Bach, Director of Maintenance, Omnitrans. 7/20/06
[25] George Karbowski, Director of Operations and Maintenance, Foothill Transit. 7/20/06

manufacturer utilize smaller engines and some bus manufacturers are developing chassis made of lightweight composite materials with reduced nominal curb weights. Even when fully loaded such buses may weigh less than 33,000 GVW[26]. Staff agrees some balance is necessary in assisting markets to develop for new technologies. Staff proposes that lightweight buses that are equipped with zero-emission engines, designed to operate in urban bus service, and carry a similar manufacturer chassis warranty could be considered an urban bus for the purpose of the zero emission bus regulation. Manufacturers would submit documentation showing how their bus technology compares to an urban bus. The Executive Officer would have discretion to determine if the bus would qualify as zero emission urban bus.

B Amendment to Reporting Requirements, title 13, CCR, section 2023.4

Staff is proposing to amend this section to extend the reporting requirements from 2015 to 2027 for transit agencies operating 150 or more urban buses. Transit agencies will be required to report:

- number of buses, manufacturer, make, and model year of engines
- fuel used for each urban bus that it currently owns or operates
- urban bus purchases and/or leases
- annual average percentage of total urban bus purchases and/or leases that were zero emission buses.

The reporting requirement is extended to allow ARB to track compliance with the Zero Emission Bus regulation and to track the fleet size of transit agencies that could through growth qualify for the ZBus purchase requirement.

[26] ARB. September 6, 2002. Staff Report: Initial Statement of Reasons. Proposed Modifications to the public transit bus fleet rule and interim certification procedures for hybrid-electric urban transit buses

VIII ENVIRONMENTAL IMPACTS

In support of the amendments to the zero emission bus regulation, staff has compiled the emissions inventory using the population reported by transit agencies and emission rates that reflect the latest inventory assumptions and urban bus rules. Survival rates (the fraction of the new vehicles that remains in the fleet after certain years) and annual mileage accrual rates by age developed for the "Proposed Amendments to the Exhaust Emission Standards for 2007-2009 Model-Year Heavy-Duty Urban Bus Engines and The Fleet Rule for Transit Agencies " were used to generate the inventory[27],[28].

For the purposes of this regulation, only emissions from transit agencies with over 200 buses at the respective implementation dates were used. In 2005, these transit agencies account for about 70 percent of all California's urban buses. Future population is based on bus survival rates and one percent growth. The proposed regulation is applicable to any transit agency that has over 200 buses during the life of the regulation. Therefore, the following table shows all the transit agencies that staff anticipates may eventually be affected by the proposed regulation, which include all transit agencies with over 150 buses. Therefore, transit agencies that have over 150 urban buses will be required to continue reporting requirements.

Table VIII-1: Transit Agencies with Over 150 Urban Buses in 2005

Agency	Regulation Effective Date	Fuel Path
Foothill Transit	Already Effected By Existing Regulation	Alt. Fuel
Los Angeles County MTA		Alt. Fuel
Orange County Transit Agency		Alt. Fuel
Sacramento Regional Transit		Alt. Fuel
San Diego Metropolitan Transit		Alt. Fuel
Alameda Contra Costa Transit		Diesel
Golden Gate Transit		Diesel
San Mateo County Transit		Diesel
Santa Clara Valley Transit		Diesel
San Francisco Municipal Railway	Meets ZBus requirements[29]	Diesel
Long Beach Transit	2008	Alt. Fuel
Santa Monica Big Blue Bus	2012	Alt. Fuel
Omnitrans	2014	Alt. Fuel
North County Transit District	unknown[30]	Alt. Fuel

[27] ARB. July 29, 2005. Staff Report: Initial Statement of Reasons, Proposed Amendments to the Exhaust Emission Standards for 2007-2009 Model-Year Heavy Duty Urban Bus Engines and the Fleet Rule for Transit Agencies.
[28] ARB. July 28, 2006. Final Regulation Order. Proposed Amendments to the Exhaust Emission Standards for 2007-2009 Model-Year Heavy Duty Urban Bus Engines and the Fleet Rule for Transit Agencies.
[29] San Francisco Municipal already exceeds the 15 percent purchase requirement through use of electric trolley buses
[30] In projected models, North County Transit District is unaffected by regulation. However, this transit agency could potentially meet the 200 bus minimum in later years.

Based on projected growth, an additional four transit agencies will be subject to the ZBus purchase requirement. Those four agencies account for an additional seven percent of all California's urban buses and are included in the state wide emission estimates. One of these transitional transit agencies, Long Beach Transit, is projected to have 200 urban buses by the 2009 trigger in the existing regulation. Therefore, Long Beach Transit is included in both the current and proposed emission scenarios. While, the other three transit agencies would not be subject to the existing regulation and are only included in the proposed emission scenarios. Table VIII-1 shows the transit agencies that are subject to the regulation. For those transit agencies that currently do not have 200 urban buses, the table identifies the year that the purchase requirement would begin, assuming the numbers grow as projected.

A Emission Standards

Staff used the emission standards for new urban transit buses shown on Table VIII-2 in calculating the emissions for the proposed regulatory amendments.

Table VIII-2: Emissions Standards (grams/brake horse power hour)

Buses Replaced	2008-2009		2010-2026	
	Diesel	NG	Diesel	NG
NMHC	0.14	0.14	0.14	0.14
CO	15.5	15.5	15.5	15.5
NOx	1.2	1.2	0.2	0.2
PM	0.010	0.010	0.010	0.010

B Current ZBus Emission Inventory

Table VIII-3 provides the estimated emission reductions from the existing regulation. The expected emission reductions were determined by calculating an emission reduction from a zero emission bus relative to a bus meeting the 2010 urban transit bus standard. This determines emission reductions above those that would be expected from a new diesel or alternative fueled bus. Actual emission reductions are higher since a new bus usually replaces a bus with at least 12 years of service, therefore retiring an older higher emitting bus[31].

Table VIII-3: Emissions Reductions from ZBuses based on Existing Regulation (Tons per Year)

Year	Oxides of Nitrogen (NOx)	Particulate Matter (PM)	Carbon Monoxide (CO)	Hydrocarbons (HC)

[31] These reductions are associated with other sections of the Fleet Rule for Transit Agencies.

2010	3.57	0.097	2.62	0.063
2015	11.7	0.620	16.8	0.405

C Proposed ZBus Emission Inventory Reduction

Table VIII-4 provides the emission impacts compared to the existing regulation from implementing Scenario 1; the current purchase requirements are delayed until 2011 for the diesel and alternative path transit agencies. Only the diesel path transit agencies conduct an Advanced Demonstration starting in 2009. The values represent the decrease in the emission reductions expected from the existing regulation.

Table VIII-4: Emissions Reductions based on Proposed Amendments from Scenario 1 Implementation (Tons per Year)

Year	NOx	PM	CO	HC
2010	(2.15)	(0.08)	(2.21)	(0.053)
2015	(2.21)	(0.08)	(2.29)	(0.055)

The existing regulation does not address purchase requirements beyond 2015 and staff assumes that purchases of zero emission buses will continue after 2015: although the percentage of the purchase is subject to a number of factors, and is not assured. The proposed regulation will guarantee that ZBus purchases and therefore emission reductions will continue through 2026, however the incremental amount of emission differences relative to the existing regulation, if any, is difficult to predict. Instead Table VIII-5, represents the emissions from the regulation as proposed.

Table VIII-5: Estimated Total Emission Reductions from the ZBus Regulation (Tons per Year)

Year	NOx	PM	CO	HC
2020	19	1.1	31	0.7
2023	22	1.3	38	0.9

D Impact of Other Compliance Scenarios

Staff estimated emissions impacts of two additional compliance scenarios. In Scenario 2, the current purchase requirements are delayed until 2011 for the diesel path transit agencies and 2012 for the alternative fuel path transit agencies that participate in the Advanced Demonstration. The diesel path transit agencies conduct an Advanced Demonstration starting in 2009 and the alternative fuel path transit agencies start the Advanced Demonstration in 2010. In Scenario 3, the current purchase requirements are delayed until 2011 for the diesel path transit agencies and 2012 for alternative fuel path transit agencies who participate in the Advanced Demonstration using the zero emission enabling bus option. The diesel path transit agencies conduct an Advanced Demonstration starting in 2009 and the alternative fuel path transit agencies start the

Advanced Demonstration in 2010. In this scenario, no emission reduction benefits are estimated for the zero emission enabling buses, such as CNG-hydrogen blended fuel buses and hydrogen internal combustion engine buses. Overall the emission impacts from Scenario 2 and 3 are similar and result in an additional emission reduction loss of about 4 percent for each pollutant compared to emission reductions seen under Scenario 1.

The use of zero emission enabling buses will create a slight reduction in emission benefits relative to allowing only ZBuses to meet demonstration requirements. Staff conservatively assumed zero emission enabling buses met the 2010 urban transit bus emission standard for purposes of this analysis even though zero emission enabling buses are expected to have much lower demonstrated emissions.

E Emission Impacts in the South Coast Air Basin

The following tables show the estimated emission impacts of the staff's proposal for the South Coast Air Basin. In general, the emission impacts of staff's revised proposal create a slight reduction in emission benefits through 2015 and an increase in emissions benefits by 2020. The effective start date of demonstration and purchase requirements is based on fuel path selected by the transit agency. All transit agencies in the South Coast Air Basin are on the alternative fuel path.

Table VIII-6 shows the emission impacts of the existing regulations. In the existing regulation alternative path transit agencies start the 15 percent ZBus purchase requirement in 2010.

Table VIII-6: South Coast Air Basin Emissions Reductions from ZBuses based on Existing Regulation (Tons per Year)

Year	NOx	PM	CO	HC
2010	0.652	0.042	1.148	0.028
2015	5.633	0.365	9.912	0.239

Table VIII-7 shows the emission impacts of Scenario 1 relative to the existing regulation, the alternative path transit agencies chose not to conduct an advanced demonstration program and the purchase requirement starts in 2011. In Scenario 2 and 3, the alternative fuel path transit agencies conduct a demonstration starting 2010 and initiate bus purchases in 2012. While Scenario 2 delays the purchase requirement for alternative fuel transit agencies, it does require some ZBus purchases one year earlier than if no demonstration was conducted. The values represent the decrease in the emission reductions expected from the existing regulation.

Table VIII-7: South Coast Air Basin Emissions Reductions based on Proposed Amendments from Scenario 1 Implementation (Tons per Year)

Year	NOx	PM	CO	HC
2010	(0.652)	(0.042)	(1.148)	(0.028)
2015	(0.417)	(0.027)	(0.734)	(0.018)

Table VIII-8 shows the reductions from the proposed regulation; Scenario 1 is used to represent the proposed amendments.

Table VIII-8: South Coast Air Basin Estimated Total Emission Reductions from the ZBus Regulation (Tons per Year)

	NOx	PM	CO	HC
2020	11	0.7	19	0.5
2023	13	0.9	24	0.6

As previously addressed, Scenario 2 and 3 are approximately the same and will not achieve as many reductions as Scenario 1, therefore the emission benefits will be less. The estimated emission reduction losses from Scenario 2 and 3 over Scenario 1 are approximately an additional 6 percent for each pollutant in the South Coast Air Basin.

IX ECONOMIC IMPACTS – COST AND COST-EFFECTIVENESS

A Legal Requirement

Sections 11346.3 and 11346.5 of the Government Code require State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment shall include a consideration of the impact of the proposed regulation on California jobs, business expansion, elimination, or creation, and the ability of California business to compete with out-of-state businesses.

State agencies are also required to estimate the cost or savings to any State or local agency and school districts in accordance with instructions adopted by the Department of Finance. This estimate is to include any nondiscretionary costs or savings to local agencies and the costs or savings in federal funding to the State.

B Affected Businesses

Any business involved in the production or use of zero emission buses potentially would be indirectly affected by the proposed regulation. Those potentially affected are manufacturers that supply components for fuel cells, batteries, integration systems, chassis, and distributors and retailers that sell such equipment. Most of these manufacturers are located outside of California. The regulation directly impacts transit agencies that operate 200 or more urban buses.

C Potential Impact on Businesses

Businesses that may be affected as a result of the proposed regulation include manufacturers of advanced, hybrid electric vehicles/engines, and urban bus manufacturers. One business that manufactures hybrid-electric engines is located in California. Therefore most impacts to these businesses, both positive and negative, will occur in other states.

Buses are manufactured in parts, one company builds the body, another the fuel cell propulsion system, and a third integrates the fueling system into the bus. Staff estimates that this proposal could potentially have adverse impacts on manufacturers of components for the zero emission buses because it delays bus purchase requirements. Staff believes that this will be realized primarily as a delay on the return of investments.

D Potential Impact on Small Businesses

Staff is not aware of any small businesses that are affected by this regulatory change.

E Potential Impact on Business Competitiveness

Staff believes there will be an effect on business competitiveness as it affects ISE Corporation (ISE), a California company that integrates the fuel cell technology, battery, and drive train components into the bus chassis. The proposed delay may allow other system integration companies to develop hybrid integration systems and these companies will likely benefit from this proposed rule, perhaps to the detriment of ISE's market. ISE is currently a leader for the integration of batteries and fuel cells in urban buses. Other transit agencies, which might have purchased the ISE integration system for the Hybrid Hydrogen Fuel Cell Buses (HHFCBs), may instead wait and purchase a HHFCBs with another system integration unit. Thus ISE may lose some of its potential market.

F Potential Impact on Employment

Staff believes that there may be some potential indirect impact on employment. With delays on investments for the fuel cell, providers may need to reduce employment numbers.

G Potential Impact on Business Creation, Elimination or Expansion

The proposed amendments could impact any of the companies involved in the manufacture, production, distribution and installation of fuel cell, alternative fuel, and diesel buses. Staff believes there will be no business elimination, and believes there will be no or minimal business creation or expansion, as a result of the adoption of the proposed amendments. Amendments to the regulation are proposed due to the bus technology not being commercially ready. A delay of the purchase requirements will make buses more cost-effective. Most manufacturers that could benefit from the potential indirect increase in business created by requiring fuel cell buses are located outside of California. To the extent that those businesses are located in California, the amendments could lead to the creation or expansion of businesses in California.

H Potential Cost to Local and State Agencies

The proposed regulation would not impose additional fiscal impacts on local public transit agencies when compared to the existing regulation. The direct economic impact is to the transit agencies. Staff projects an estimated cost savings to transit agencies of approximately $59 million over the four year period beginning January 2008.

1 <u>Implementation Support</u>

To determine implementation scenarios for costs, staff first evaluated existing funding available for transit agencies. Transit agencies use Federal Transit Administration (FTA) moneys and State and local matching funds to replace their buses. A vehicle's service life determines when a transit agency can apply for FTA funding, and the local transportation agency prioritizes which transportation projects in its area obtain funding first (or in a fiscal year). Turnaround time for funding can be up to two years from the initial request.

2 Implementation Costs

Table IX-1 represents the incremental cost savings, while Table IX-2 includes the incremental cost to all affected transit agencies for ZBuses. The incremental cost represents the cost of a ZBus over the cost of a diesel bus. Delaying the current purchase requirements and including an Advanced Demonstration prevents an expenditure of over $59 million dollars from 2008 through 2012 (including estimated infrastructure costs).

Table IX-1: Cost Savings of the Proposed Regulation Compared to the Existing Regulation

Year	Scenario 1	Scenario 2	Scenario 3
2008	$19,000,000	$19,000,000	$19,000,000
2009	($1,900,000)	($1,900,000)	($1,900,000)
2010	$34,300,000	$25,300,000	$29,500,000
2011	$7,800,000	$36,600,000	$36,600,000
2012	$0	$9,000,000	$4,800,000
2015	$0	$0	$0

As shown in **Table IX-1**, during the current regulation, 11 buses would have been purchased in 2009. The proposed amendments require at least a 12 bus demonstration. Therefore in 2009 an additional cost of $1.9 millions is shown.

Table IX-2: Cost of Regulation Scenarios

Year	Existing regulation	Scenario 1	Scenario 2	Scenario 3
2008	$19,000,000	$0	$0	$0
2009	$20,900,000	$22,800,000	$22,800,000	$22,800,000
2010	$34,300,000	$0	$9,000,000	$4,800,000
2011	$39,850,000	$32,050,000	$3,250,000	$3,250,000
2012	$39,900,000	$39,900,000	$30,900,000	$35,100,000
2015	$58,500,000	$58,500,000	$58,500,000	$58,500,000
2020	not under regulatory mandate	$44,300,000	$44,300,000	$44,300,000
2023		$35,550,000	$36,150,000	$36,150,000

Table IX-2, the incremental cost of the Advanced Demonstration is approximately $23 million for the diesel path transit agencies and varies between $5 million and $9 million for alternative fuel path transit agencies, depending on the demonstration option selected. In addition, alternative fuel path transit agencies will also incur infrastructure costs to implement the Advanced Demonstration. Diesel path transit agencies will be able to utilize established infrastructure although additional infrastructure could be required.

The cost of purchasing the buses for the purchase requirement for all transit agencies starting in 2011 will range from $32 million starting in 2012 to $59 million in 2015. The increase in total expenditure is caused by the growth in the transit bus fleet and the addition of the transitional transit agencies into the purchase requirement. Variations from year to year are attributed to transit agency purchase cycle and the age of the fleet.

Infrastructure costs were not included into the annualized cost of the proposed regulation or the current regulation. These costs were not included since it is difficult to determine the number of stations, station size, type of infrastructure, and when they would need to be built for each transit agency. Transit agencies entering into the purchasing requirement later might end up only needing a small station able to handle 20 fuel cell buses, while an agency like MTA will need infrastructure capable of handling more than 200 fuel cell buses, perhaps at several yards.

Only two hydrogen fuel stations capable of fueling urban fuel cell buses have been built in California: staff does not believe that these current infrastructure costs are appropriate for use in projections. VTA's infrastructure costs included a semi-permanent hydrogen station able to service between 15 and 20 buses, a new bus wash and retrofitted maintenance facility, at a cost of $4.4 million[7]. AC transit put in place a hydrogen fueling station capable of servicing five to six buses per day for approximately $4 million, and retrofitted a diesel maintenance bay and bus wash for $1.2 million, bringing the total to $5.2 million dollars[19]. Using this information, the cost of infrastructure is around $300,000 to $900,000 per bus. This cost is comparable to infrastructure for electric trolleys, another zero-emission technology, which is approximately $800,000 per trolley bus. Several projects are proposed throughout the world and these costs could be more appropriate to determine the future infrastructure costs, unfortunately this information is considered confidential.

Costs for hydrogen infrastructure are not comparable with either CNG or diesel infrastructure for many reasons. CNG and LNG fueling stations can serve up to 250 buses per day and cost between $23,000 and $39,000 per bus, respectively[23]. While, current hydrogen stations are only intended to service between 6 and 20 fuel cell buses. Hydrogen stations are also currently being used for testing and research purposes. Transit agencies as well as energy providers are willing to invest relatively larger sums of money in order to expand their understanding of hydrogen refueling technology and interface. Additionally, prototype and demonstration phases are inherently more expensive than commercial products. Staff expects costs for hydrogen fueling stations to decrease and the number of buses serviced to increase over time as more and more demonstrations are executed. However, unlike electric trolley bus, CNG, and LNG infrastructure, hydrogen infrastructure is still in its development stages, and therefore more expensive. Staff anticipates that infrastructure costs will decrease as the technology for producing and dispensing hydrogen evolves.

In addition, fuel cell bus providers and transit agencies expect the fuel cell buses to eventually have reduced operating and maintenance costs[4]. Initial fuel economy values from the current AC Transit operations indicate a 100 percent fuel economy improvement compared to diesel. Costs per kilogram of hydrogen are expected to decrease as production processes are optimized, while diesel costs are rising yearly as oil sources are depleted. Hydrogen, a renewable resource, can be produced from a variety of different feedstock. UTC predicts fuel cell bus operation costs per mile to drop below diesel and CNG to thirty cents per mile[4]. Maintenance and operation costs of the mature hybrid fuel cell system are expected to be reduced relative to electric trolley buses, which have proven to be less in comparison to diesel buses.

The cost estimates are not indicative of the actual direct cost to transit agencies. Transit agencies typically receive federal and regional funds for the acquisition of buses and implementing alternative fuel infrastructure. The FTA funds 80-percent of the cost of a diesel bus and 90-percent of the incremental cost of an alternatively fueled bus. In addition, currently proposed federal legislation would provide 100 percent of the incremental cost of hybrid buses. The majority of the cost of buses is covered through federal co-funding; however, the total amount of federal funding is limited. The distribution of the federal funds is administrated by regional transit commissions. Funding is also available for infrastructure, however, the amount of federal and State co-funding for alternative fuel infrastructure has varied.

I Cost to Individuals

Raising fares is one of the few ways transit operators can raise revenues. However, fare box revenues represent a minority of operating expenses, and staff believes, based on discussions with transit operators, that they are rarely used for capital expenditures. In 2005, the average operating revenue from fares from transit agencies operating at least 100 urban buses was 31.75 percent[32]. Staff was unable to provide a reasonable estimate of potential costs to individuals because of several factors, including monthly passes and discounts on ticket books with multiple tickets. Therefore, we cannot predict if or how transit agencies would raise fares.

J Benefits

1 Cost-Effectiveness of Proposed Regulation

Based on costs presented by fuel cell, chassis, system integrators, and transit operators for costs of implementing ZBuses staff determined that at least for the early years of the program the dollars spent per ton of pollutant reduced under the ZBus program will be

[32] ARB. January 7, 2005. Staff Report: Initial Statement of Reasons. Proposed Modifications To The Fleet Rule For Transit Fleet Vehicles.

much higher than for typical ARB regulatory measures. Staff estimated the initial cost effectiveness of the proposed regulation to be $380 per pound of NOx. Staff anticipates the actual cost per pound to be lower, since this cost does not include life-cycle cost savings. In addition, this value does not include funding received from any government funding sources, such as the Federal Transit Administration (FTA).

Although the initial purchase costs may still be higher than conventional diesel and alternative fuel bus technology, the price is more comparable to an electric trolley bus. As technology is optimized, fuel cell bus operation and maintenance costs are estimated to be in line with electric trolley buses, and significantly lower than diesel and alternative fuel buses. When incorporating these factors along with additional improvements to fuel cell technology, staff anticipates that life cycle costs will decrease the cost per pound of emission reduced. The Board has confirmed in previous regulatory decisions, zero emission vehicle programs are an essential component of the State's long-term air-quality strategy. This regulation provides a necessary avenue to bring this technology to the market.

K Potential Negative Impacts

There is a potential for a decrease in the emission benefits from years 2008 through 2017. However, there may also be a potential increase in the emission benefits from 2018 and beyond relative to keeping the existing regulation. However, staff does not expect ZBus technology to be cost effective in time for the existing purchase implementation date. Therefore transit agencies, in order to comply with the purchase regulations, may have to reduce the number of new buses acquired annually and thereby keeping older higher emitting buses in operation longer.

L Incentives and Early Implementation

Incentive programs have the ability to prompt emissions benefits early or beyond those required by regulations. California has the largest incentive program in the nation, with over $140 million available each year through State and local funds. Even at this level funding is far from sufficient to pay for all the reductions needed to provide clean air. Reductions required by regulations, and funded by owners of the affected equipment, will still provide the majority of emission reductions.

Currently, incentive programs, such as the Carl Moyer Program, provide modest funding for fuel cell projects[33]. With the adoption of the proposed regulation, most of the incentive projects for zero emission buses would no longer be eligible for funding. Fleets that demonstrate full compliance with their fleet-average and zero emission bus requirements would be eligible for incentive funds to further reduce emissions. Eligible projects would include electric trolleys, fuel cell buses, and fuel cell hybrid electric buses.

[33] ARB. January 6, 2006. The Carl Moyer Program Guidelines, Approved Revision 2005.

X ISSUES

Over the course of development of this proposal, staff has met many times with various stakeholders and received written and verbal comments. Although staff has considered each comment, not all issues could be resolved. Following is a discussion of major outstanding issues.

A Purchase requirement should be delayed until 2014 for diesel path transit agencies and 2016 for alternative fuel path transit agencies in order to ensure that cost and performance targets are met.

Staff has included a provision that allows the Executive Officer to reduce the ZBus purchase requirement, if performance and cost goals are not met. Staff believes that with this provision, the regulation provides assurances to the transit agencies that the technology will be commercially viable when the 15 percent purchase requirement is implemented.

B Alternative Fuel Path Transit Agencies should not be required to conduct an Advanced Demonstration

Staff has compared the alternative fuel path transit agencies costs for switching to alternative fuel buses and balanced that with the costs the diesel fuel path transit agencies have incurred on the zero emission initial demonstration program. Staff determined that emission reductions were gained in the early years from transit agencies on the alternative fuel path, however, the information gained from the diesel path transit agencies demonstrations to move buses to a zero emission status is just as valuable. Diesel path transit agencies have implemented advanced diesel emission reduction technologies on existing fleets. Since 2000, the transit agencies affected by the ZBus regulation have made significant upgrades to meet the necessary requirements in the Fleet Rule for Transit Agencies[1]. For each demonstration, the diesel path agencies have paid over $5 million per fuel cell bus including infrastructure, while, the alternative fuel path agencies have paid close to $32,000 per bus. Unlike the diesel path projects, the alternative fuel path transit agency projects were able to qualify for Carl Moyer funding to replace their fleets with CNG buses[33]. For these reasons, staff proposes that distinction in how the two paths are treated under the ZBus regulation be revised and that the alternative path transit agencies be given the option to participate in the Advanced Demonstration or align the purchase requirements with the Diesel Path Transit Agencies.

C Buses shorter than an Urban Bus should be included as Zero Emission Buses

Staff was asked to consider whether smaller, battery dominant, fuel cell buses of approximately 22 foot length could be considered to be urban buses. Staff reviewed this option and determined that this type of bus would not be deployed in typical urban bus service. In addition, the technology and infrastructure requirements for the operation of shorter buses are sufficiently different to minimize the technology transfer to urban buses. The transit regulation was intended to reduce the emissions from the predominant type of transit vehicle in use, the "urban" bus. In addition, no transit agency indicated that they would be inclined to replace urban transit buses with shorter buses. Therefore staff did include shorter, battery dominant, fuel cell buses as a means to meet the purchase requirements of the regulation.

XI ATERNATIVES AND RECOMMENDATION

No alternative considered by the ARB would be more effective in carrying out the goals previously endorsed by the Board in the 2000 regulation than the proposed amendments, nor would any alternative be both as effective and least burdensome to affected private persons than the proposed amendments. The following options were considered in reaching this conclusion.

A Alternatives Considered

During the regulatory development process, ARB staff presented a variety of proposals that were similar in structure to the current proposal including:

- Non Urban Zero Emission Buses
- Fleet-Average Standards
- Near-Zero Emission Requirements
- Earlier Zero Emission Requirements dates
- Earlier Advanced Demonstration dates

Each of the elements noted was considered both independently and in combination.

B April 2006 Draft Proposal

In April of this year staff first provided, in a formal presentation, the requirements of the Advanced Demonstration concept. In general, transit agencies were supportive of the concept but found staff's requirements regarding multi transit agencies demonstrations too prescriptive to the participating agencies. In addition, while the proposal achieved greater emission reductions; staff believes that the risk of potential negative economic impact of that proposal was too high. Without the executive officer discretion clause, the proposal would have set firm purchase requirement implementation dates that could have required reviews and revisions. The current proposal provides more flexibility and sets a more appropriate balance between technical feasibility and cost to affected industries and transit agencies.

C No Amendments to the ZBus Purchase Requirements

Not amending this regulation would have the effect of requiring the purchase of ZBuses in California from 2008 through 2015 by transit agencies at a volume of more than 200 urban buses. ZBus technology has not demonstrated reasonable cost or durability for this level of integration into the transit bus fleet. California's regulations for transit agencies and urban buses are innovative and go beyond the federal requirements for urban buses. At the time they were adopted, it was anticipated that changes could be necessary based upon the state of the technology. Not amending this regulation would also result in higher emissions than the proposal, because the costs of the ZBus would force the transit agencies to extend the life of older higher emitting diesel buses due to costs associated with the ZBus technology.

Since the original rule adoption in 2000, many transit agencies have installed natural gas refueling infrastructure and purchased alternative-fuel urban buses; re-powered diesel engines to engines meeting cleaner exhaust emission standards; installed particulate filters in diesel engines; and experimented with developing technologies, such as hybrid-electric engines and cleaner fuels. Many of California's transit agencies continue to take on the challenge to be innovators and incubators for advanced technologies. Not adopting these amendments would hurt the continuing efforts to advance innovative technologies needed to meet future emission objectives. Staff does not recommend the Board endorse the "no change" alternative.

D Eliminate Zero Emission Bus Requirement

Despite the achievements in motor vehicle emission reductions to date, the vast majority of Californians live in areas of the state that still do not meet State or federal health-based ambient air quality standards. The ZBus technology is a vital component of ARB's strategy to pursue emission reductions from all feasible sources in order to continue our progress toward clean air and to meet and sustain air quality goals. While the goals of the 2000 regulation have not been demonstrated, progress has been made and much has been learned about fuel cell bus technology. Additionally, the momentum around the world to demonstrate and incorporate fuel cell buses into urban transit fleets indicates that abandonment of the ZBus requirement would not be appropriate.

E Conclusion

Having considered all of these alternatives, staff concludes that the proposed amendments to the regulation are the most appropriate to achieve feasible and beneficial implementation of ZBus technology

XII SUMMARY AND STAFF RECOMMENDATION

A Summary of Staff's Proposal

As presented in the previous sections, the ARB staff's proposal is designed to continue placements of ZBuses in California's urban transit fleets through technology demonstration and measured introduction of purchase requirements. ARB staff acknowledges that the 2006 rulemaking is a "technology-forcing" regulation. All indications point to the technology becoming feasible and cost effective. However, since the performance and cost effectiveness of the technology has yet to be demonstrated staff is including the Executive Officer discretion clause. The staff's proposal includes the following:

- Add an Advanced Demonstration for the diesel path transit agencies in 2009, and an optional demonstration for the alternative fuel path transit agencies in 2010;
- Postpone the ZBus requirement by three years for diesel path transit agencies, two years for alternative fuel path transit agencies in the Advanced Demonstration, and one year for those alternative fuel path transit agencies choosing not to participate in the demonstration;
- Include an Executive Officer Discretion clause that can be used to determine the status of the technology, and reduce the percentage of the purchase requirement if performance goals are not met.

B Staff Recommendation

ARB staff recommends the Board adopt the proposed amendments to sections 2023.1, 2023.3 and 2023.4, title 13, chapter 1, article 4, CCR, in its entirety. The regulation is set forth in the proposed regulation order in Appendix A.

No alternative considered by the agency would be more effective in carrying out the purpose for which the regulation is proposed or would be as effective as or less burdensome to affected private persons than the proposed regulation.

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XIV APPENDIX A: Proposed Regulation

PROPOSED REGULATION ORDER

Amend, adopt or repeal the following sections of title 13, California Code of Regulations, to read as set forth in the following pages:

Amend:	
Section 2023.1	Fleet Rule for Transit Agencies-Urban Bus Requirements
Section 2023.3	Zero-Emission Bus Requirements
Section 2023.4	Reporting Requirements for Transit Agencies

Note: In this Proposed Regulation Order, the proposed amendments are shown in single underline to indicate additions and ~~single strikeout~~ to indicate deletions. On July 28, 2006, the Air Resources Board submitted to the Office of Administrative Law (OAL) amendments that add subsections 2023.1(a)(4) and (5), and 2023.4(b)(4) and had been approved by the Air Resources Board at hearings on September 15 and October 20 and 27, 2005. OAL has until September 12, 2006 to determine whether to approve the amendments, which are shown here in *times new roman italics*. All of the amendments in that rulemaking can be found at http://www.arb.ca.gov/regact/sctransit/fro.pdf). Subsection headings are shown in *italics* and are to be italicized in Barclays California Code of Regulations.

§ 2023.1 Fleet Rule for Transit Agencies – Urban Bus Requirements.

(a) To encourage transit agencies that operate urban bus fleets to purchase or lease lower emission alternative-fuel buses, while also providing flexibility to such fleet operators to determine their optimal fleet mix in consideration of such factors as air quality benefits, service availability, cost, efficiency, safety, and convenience, two paths to compliance with this fleet rule are available: the alternative-fuel path and the diesel path.

(1) Transit agencies must choose their compliance path, and shall notify ARB of their intent to follow either the diesel or the alternative-fuel path, by January 31, 2001. Reporting requirements for that notification are set forth in subdivisions (a) and (b) of section 2023.4, title 13, CCR.

(2) A transit agency within the jurisdiction of the South Coast Air Quality Management District may elect to change its compliance path from the diesel path to the alternative-fuel path, provided that the transit agency notifies the Executive Officer of the change by January 31, 2004, and provided that the transit agency is in compliance with all requirements of section 2023.1, including specific requirements of the diesel path, on or before January 1, 2004. Reporting requirements for this notification are set forth in paragraph (b)(3) of section 2023.4, title 13, CCR.

(3) A new transit agency that is a successor to an existing transit agency or that has been created from a merger of two or more transit agencies or parts of two or more transit agencies must have the same compliance path as the transit agency or agencies out of which it is formed.

(4) A transit agency within the jurisdiction of the South Coast Air Quality Management District shall follow the alternative-fuel path. If the transit agency had previously stated its intent to follow the diesel path, the change to the alternative-fuel path shall be effective on [Insert effective date of subsection].

(5) Transit agencies on the diesel path with more than 30 buses in their fleets purchasing model year 2007 through 2009 urban buses that are not certified at or below 0.2 g/bhp-hr NOx emission level shall:

(A) Mitigate the increased NOx emissions for each urban bus purchased by retrofitting an existing urban bus or transit fleet vehicle within the fleet with a level 3 particulate matter (PM) verified diesel emission control strategy with an oxides of nitrogen (NOx) reduction efficiency of at least 40 percent, if available, otherwise, with a NOx reduction efficiency of at least 25 percent. This retrofit requirement applies on a one-to-one basis until all diesel urban buses and transit fleet vehicles within the transit

agency's fleet are either retrofitted or are determined to be unable to be retrofitted as specified in (B) below.

(B) *Obtain Executive Officer approval for purchasing a 2007 through 2009 model year urban bus not subject to (A) above by submitting to the Executive Officer a report 90 days prior to the delivery of the urban bus. The report shall provide information that demonstrates that all vehicles in the transit agency's fleet have been retrofitted or are determined to be unable to be retrofitted including when the inability to retrofit occurs for reasons other than a device not verified for the specific urban bus or transit fleet vehicle engine family.*

(C) *Submit annual reports that meet the requirements in section 2023.4(b)(4).*

(b) Transit agencies on the alternative-fuel path shall meet the following requirements:

(1) Upon approval of the regulation, and through Model Year 2015, at least 85 percent of all urban buses purchased or leased each year must be alternative-fuel buses or buses with engines purchased under paragraph (b)(9).

(2) NOx fleet average requirements as set forth in subdivision (d), below.

(3) Beginning October 1, 2002, only engines certified to an optional PM standard of 0.03 g/bhp-hr or lower shall be purchased when making new bus purchases.

(4) Total diesel PM emission reduction requirements and use of low-sulfur or other allowed fuel as set forth in subdivision (e), below.

(5) Transit agencies on the alternative-fuel path shall not purchase any diesel-fueled, dual-fuel, or bi-fuel buses with 2004 - 2006 model year engines certified to emissions levels in excess of those specified in paragraph (a)(11) of section 1956.1, title 13, CCR, except as provided in paragraph (b)(8) or (b)(9) of this section.

(6) Zero-emission bus purchase requirements for transit agencies opting out of the advanced demonstration will align with the diesel path agencies and beginning in model year ~~2010~~2011, in accordance with the requirements set forth in subdivision (c) of section 2023.3, title 13, CCR.

(7) Reporting requirements as set forth in section 2023.4, title 13, CCR.

(8) The Executive Officer may exempt transit agencies on the alternative-fuel path from the requirements of paragraph (b)(5) of section 2023.1, title 13, CCR, provided that:

(A) A transit agency applies to the Executive Officer for such exemption by June 30, 2001;

(B) A transit agency demonstrates to the Executive Officer that it will achieve NOx emissions benefits through 2015 greater than what would have been achieved through compliance with paragraph (b)(5); and

(C) The Executive Officer finds that transit agencies, after consulting with the Engine Manufacturers Association, have demonstrated, or are contractually committed to demonstrate, advanced NOx aftertreatment technology.

(9) A transit agency on the alternative-fuel path may purchase a bus operated with a heavy-duty pilot ignition engine provided the engine meets the standards set forth in subdivision (b) of section 1956.1, title 13, CCR.

(10) Purchase requirements for a transit agency participating in a zero-emission bus demonstration (as defined in subdivision (b) of section 2023.3, title 13, CCR) will begin with model year 2012 in accordance with the requirements set forth in subdivision (c) of section 2023.3, title 13, CCR.

(c) Transit agencies on the diesel path shall meet the following requirements:

(1) NOx fleet average requirements as set forth in subdivision (d), below.

(2) Total diesel PM emission reduction requirements and use of low-sulfur or other allowed fuel as set forth in subdivision (e), below.

(3) Zero-emission bus demonstration as required in subdivision (b) of section 2023.3, title 13, CCR.

(4) Transit agencies on the diesel path shall not purchase any diesel-fueled, dual-fuel, or bi-fuel buses with 2004 - 2006 model year engines certified to emissions levels in excess of those specified in paragraph (a)(11) of section 1956.1, title 13, CCR, except as provided in paragraph (c)(7) or (c)(8) of this section. Beginning July 1, 2003, a transit agency may not purchase alternative fuel buses certified to a PM emission level in excess of the optional standard of 0.03 g/bhp-hr when making new bus purchases.

(5) Zero-emission bus purchase requirements beginning in model year ~~2008~~2011, in accordance with the requirements set forth in subdivision (c) of section 2023.3, title 13, CCR.

(6) Reporting requirements as set forth in section 2023.4, title 13, CCR.

(7) The Executive Officer may exempt transit agencies on the diesel path from the requirements of paragraph (c)(4) of section 2023.1, title 13, CCR, provided that:

(A) A transit agency applies to the Executive Officer for such exemption by June 30, 2001;
(B) A transit agency demonstrates to the Executive Officer that it will achieve NOx emissions benefits through 2015 greater than what would have been achieved through compliance with paragraph (c)(4); and
(C) The Executive Officer finds that transit agencies, after consulting with the Engine Manufacturers Association, have demonstrated, or are contractually committed to demonstrate, advanced NOx aftertreatment technology.

(8) A transit agency on the diesel-fuel path may purchase a bus operated with a heavy-duty pilot ignition engine provided the engine meets the standards set forth in subdivision (b) of section 1956.1.

(9) The Executive Officer shall authorize, in writing, a transit agency on the diesel path to purchase one or more diesel-fueled hybrid-electric bus certified under title 13, CCR, section 1956.1(a)(11)(B) provided that:

(A) The transit agency shall submit a mitigation plan and letter requesting approval by January 31, 2005, to the Executive Officer that demonstrates that the transit agency will provide surplus emission reductions from urban buses in its fleet that will offset the NOx emission difference between the certified NOx emission standard of the hybrid-electric bus and 0.5 g/bhp-hr. The transit agency may not use NOx emission reductions that are otherwise required by any statute, regulation, or order or the emission reductions that will accrue from the retirement of an urban bus to be replaced by a hybrid-electric bus for the offset;
(B) The transit agency shall complete implementation of all mitigation measures set forth in the approved plan to offset NOx emissions prior to the receipt of the last diesel-fueled hybrid-electric bus; and
(C) The transit agency shall submit the reports required by section 2023.4(g).

(d) Beginning October 1, 2002, no transit agency shall own, operate, or lease an active fleet of urban buses with average NOx emissions in excess of 4.8 g/bhp-hr, based on the engine certification standards of the engines in the active fleet.

(1) This active fleet average requirement shall be based on urban buses owned, operated, or leased by the transit agency, including diesel buses, alternative-fuel buses, all heavy-duty zero-emission buses, electric trolley buses, and articulated buses, in each transit agency's active fleet. The Executive Officer may allow zero-emission buses that do not meet the definition of an urban bus to be included in the calculation of the fleet average standard upon written request to the ARB by January 31, 2002, and upon approval by the Executive Officer. The request shall include a description of the zero-emission buses, the zero-emission technology utilized, and the number of zero-emission buses to be used in calculating the NOx fleet average standard. Zero-emission buses not meeting the definition of an urban bus may not be used to satisfy the requirements of the Zero-emission Bus Demonstration Project set forth in subdivision (b) of section 2023.3, title 13, CCR.

(2) Transit agencies may use ARB-certified NOx retrofit systems to comply with the fleet average requirement (in addition to bus purchases, repowerings, and retirements).

(3) Transit agencies have the option of retiring all 1987 and earlier model year diesel urban buses by October 1, 2002, to comply with the fleet average standard requirement.

(4) A transit agency established after January 1, 2005, shall not operate an active fleet of urban buses with an average NOx emission in excess of:

(A) 4.0 g/bhp-hr, or
(B) the NOx average of the active fleet of the transit agency from which it was formed, whichever is lower, or
(C) in the case of a merger of two or more transit agencies or parts of two or more transit agencies, the average of the NOx fleet averages, whichever is lower.

(e) To reduce public exposure to diesel particulate matter, each transit agency shall reduce the diesel PM emission total of the diesel buses in its active fleet relative to its diesel PM emission total as of January 1, 2002, according to the schedule below, and shall operate its diesel buses on diesel fuel with a maximum sulfur content of 15 parts per million by weight. Documentation of compliance with these requirements must be provided in accordance with the provisions of subdivision (d) of section 2023.4, title 13, CCR.

(1) No later than January 1, 2004:

(A) The diesel PM emission total for a transit agency on the diesel path shall be no more than 60 percent of its diesel PM emission total on January 1, 2002.
(B) The diesel PM emission total for a transit agency on the alternative fuel path shall be no more than 80 percent of its diesel PM emission total on January 1, 2002.

(2) No later than January 1, 2005:

(A) The diesel PM emission total for a transit agency on the diesel path shall be no more than 40 percent of its diesel PM emission total on January 1, 2002.
(B) The diesel PM emission total for a transit agency on the alternative fuel path shall be no more than 60 percent of its diesel PM emission total on January 1, 2002.

(3) No later than January 1, 2007:

(A) The diesel PM emission total for a transit agency on the diesel path shall be no more than 15 percent of its diesel PM emission total on January 1, 2002 or equal to 0.01 g/bhp-hr times the total number of current diesel-fueled active fleet buses, whichever is greater.
(B) The diesel PM emission total for a transit agency on the alternative fuel path shall be no more than 40 percent of its diesel PM fleet average on January 1, 2002.

(4) No later than January 1, 2009, the diesel PM emission total for a transit agency on the alternative fuel path shall be no more than 15 percent of its diesel PM emission total on January 1, 2002 or equal to 0.01 g/bhp-hr times the total number of current diesel-fueled active fleet buses, whichever is greater.

(5) Beginning on January 1, 2005, a new transit agency may not have a diesel PM emission total exceeding the following values:

(A) As of January 1, 2005 through December 31, 2009, 0.05 g/bhp-hr (exhaust emission value) times the total number of diesel-fueled buses in the active fleet;
(B) As of January 1, 2010, 0.01 g/bhp-hr (exhaust emission value) times the total number of diesel-fueled buses in the active fleet.

(6) Beginning July 1, 2002, a transit agency shall not operate its diesel urban buses on diesel fuel with a sulfur content in excess of 15 parts per million by weight, except that a transit agency may operate its diesel buses on a fuel that is verified by the Executive Officer as a diesel emission control

strategy that reduces PM in accordance with section 2700 et seq., title 13, CCR. A transit agency with fewer than 20 buses in its active fleet, and that operates in a federal one-hour ozone attainment areas, is not subject to this low-sulfur fuel requirement until July 1, 2006. In areas redesignated as one-hour ozone non-attainment areas prior to July 1, 2006, a transit agency initially exempt from the low-sulfur fuel requirement shall submit a plan to the Executive Officer within 30 days of redesignation for achieving compliance with this requirement.

NOTE: Authority cited: Sections 39600, 39601, 39667, 43013, 43018 and 43701(b), Health and Safety Code. Reference: Sections 39002, 39003, 39017, 39500, 39650, 39667, 40000, 43000, 43000.5, 43013, 43018, 43701(b), 43801, 43806 Health and Safety Code, and sections 233 and 28114, Vehicle Code.

[Included for context only]

§ 2023.2 Fleet Rule for Transit Agencies – Transit Fleet Vehicle Requirements.

(a) A transit agency shall not operate transit fleet vehicles with a NOx fleet average exceeding the following values as of the specified dates. A transit agency shall provide documentation of compliance with the requirements in accordance with the provisions of subdivision (e)(2) of section 2023.4, title 13, CCR.

(1) Beginning December 31, 2007 through December 30, 2010, 3.2 g/bhp-hr;

(A) A transit agency may retire all 1997 and earlier model year engines in transit fleet vehicles by December 31, 2007, to comply with the NOx fleet average requirement.

(B) For a new transit agency established after December 31, 2007 and through December 31, 2009, either 3.2 g/bhp-hr or no higher than the NOx average of the transit fleet vehicles of the transit agency from which the new transit agency has been formed, whichever is lower.

(2) Beginning December 31, 2010, 2.4 g/bhp-hr;

(A) A transit agency may retire all 2001 and earlier model year engines in transit fleet vehicles by December 31, 2010, to comply with the NOx fleet average requirement.

(B) For a new transit agency established after December 31, 2010, either 2.4 g/bhp-hr or no higher than the NOx average of the transit fleet vehicles of the transit agency from which the new transit agency has been formed, whichever is lower.

(3) Zero-emission buses used to satisfy the requirements set forth in subdivision (d) of section 2023.1 may not be used to meet the requirements of this subdivision.

(4) A transit agency may claim NOx reductions by application of a system that has been verified by the Executive Officer in accordance with section 2700 et seq., title 13, CCR to comply with the fleet average requirement, in addition to transit fleet vehicle purchases, retirements, or engine repowering.

(a) A transit agency shall reduce the total diesel particulate matter (PM) emissions of its diesel transit fleet vehicles relative to its total diesel PM emissions from diesel transit fleet vehicles as of January 1, 2005, according to the schedule below. "Diesel PM emission total" and how it is calculated are defined in 2023(a)(3). A transit agency shall provide documentation of compliance with these requirements in accordance with the provisions of subdivision (e)(3) of section 2023.4, title 13, CCR.

(1) No later than December 31, 2007, the diesel PM emission total for a transit agency's transit fleet vehicle fleet shall be no more than 60 percent of its diesel PM emission total on January 1, 2005.

(2) No later than December 31, 2010, the diesel PM emission total for a transit agency's transit fleet vehicle fleet shall be no more than 20 percent of its diesel PM emission total on January 1, 2005, or equal to 0.01 g/bhp-hr times the total number of transit fleet vehicles in the current fleet, whichever is greater.

(3) A new transit agency established after January 1, 2005, may not have a diesel PM emission total exceeding the following values:
   (A) For a new transit agency established January 1, 2005 through December 31, 2006, 0.1 g/bhp/hr (exhaust emission value) times the number of diesel-fueled transit fleet vehicles in its fleet. This value will serve as the transit agency's PM baseline. The transit agency must meet the requirements set forth in section 2023.2(b)(1) and (2).
   (B) For a new transit agency established January 1, 2007 through December 31, 2009, 0.1 g/bhp/hr (exhaust emission value) times the number of diesel-fueled transit fleet vehicles in its fleet. This value will serve as the transit agency's PM baseline and shall be reduced by 50 percent of its PM baseline value by December 31, 2010, and 80 percent by December 31, 2012.
   (C) For a new transit agency established January 1, 2010 or later, 0.01 g/bhp-hr (exhaust emission value) times the total number of diesel transit fleet vehicles in its fleet.

(c) A transit agency may apply to the Executive Officer for a delay in meeting the provisions of section 2023.2(a) and 2023.2(b) for up to one year to allow for the termination of a vehicle lease, maintenance/lease, turnkey or vehicle/service contract as defined by the Federal Transit Administration (FTA). The transit agency shall apply to the Executive Officer no later than 90 days prior to the applicable deadlines and shall include a description of the reason the delay is required, the reason the contractor cannot provide a newer vehicle to replace an existing vehicle within the terms of the contract, and provide a schedule for compliance by the end of the compliance extension.

NOTE: Authority cited: Sections 39600, 39601, 39659, 39667, 39701, 41511, and 43018 Health and Safety Code. Reference: Sections 39667, 39700, 39701, 41510, 41511, 43000, 43000.5, 43013, 43018, 43801, and 43806 Health and Safety Code.

§ 2023.3 Zero-Emission Bus Requirements.

(a) "Zero-emission bus" means an Executive Officer certified urban bus that produces zero exhaust emissions of any criteria pollutant (or precursor pollutant) under any and all possible operational modes and conditions.

(1) A hydrogen-fuel cell bus shall qualify as a zero-emission bus.

(2) An electric trolley bus with overhead twin-wire power supply shall qualify as a zero-emission bus.

(3) A battery electric bus shall qualify as a zero-emission bus.

(4) Incorporation of a fuel-fired heater shall not preclude an urban bus from being certified as a zero-emission bus, provided the fuel-fired heater cannot be operated at ambient temperatures above 40°F and the heater is demonstrated to have zero evaporative emissions under any and all possible operational modes and conditions.

(b) ~~Zero-emission Bus Demonstration Project~~ *Zero-Emission Bus Demonstration Projects.* ~~– except as provided in (3) below, the owner or operator of an urban bus fleet on the diesel path in accordance with the provisions of section 2023.1, with more than 200 urban transit buses in its active fleet on January 31, 2001, shall implement a demonstration project. The owner or operator shall evaluate the operation of zero-emission buses in revenue service, and prepare and submit a report on the demonstration project to the Executive Officer for inclusion in a future review of zero-emission technology.~~

(1) *Initial Demonstration Project.*

(A) Except as provided in (D) below, the owner or operator of an urban bus fleet on the diesel path in accordance with the provisions of section 2023.1, with more than 200 urban transit buses in its active fleet on January 31, 2001, shall implement an Initial Demonstration Project in accordance with this subsection (b)(1). The owner or operator shall evaluate the operation of zero-emission buses in revenue service, and prepare and submit a report on the demonstration project to the Executive Officer for inclusion in a future review of zero-emission technology.

(B)~~(1)~~This Initial ~~D~~Ddemonstration ~~P~~Pproject shall meet all of the following specifications and requirements:

~~(A)~~1. utilize a minimum of three zero-emission buses,

~~(B)~~2. include any necessary site improvements,
~~(C)~~3. locate fueling infrastructure onsite,
~~(D)~~4. provide appropriate maintenance and storage facilities,
~~(E)~~5. train bus operators and maintenance personnel,
~~(F)~~6. place the buses in revenue service for a minimum duration of 12 calendar months,
~~(G)~~7. retain operation and maintenance records, and
~~(H)~~8. report on the demonstration as ser forth in subdivision (f) of section 2023.4, title 13 CCR.

(C)~~(2)~~When planning and implementing the Initial D~~d~~emonstration P~~p~~roject, the operator or owner shall meet the following milestones:

~~(A)~~1. no later than January 1, 2002, prepare and solicit bid proposals for materials and services necessary to implement the demonstration project, including but not limited to the zero-emission buses and the associated infrastructure
~~(B)~~2. no later than February 28, 2006, place at least three zero-emission buses in operation, and
~~(C)~~3. no later than July 31, 2005, submit a preliminary report on the demonstration project to the Executive Officer, in accordance with paragraph (f)(3) of section 2023.4, title 13, CCR and,
~~(D)~~4. no later than July 31, 2007, submit a report on the demonstration project to the Executive Officer, in accordance with paragraph (f)(4) of section 2023.4 ~~T~~title 13, CCR.

(D) ~~(3)~~Multiple transit agencies within the same air basin may, on a case-by-case basis, petition the Executive Officer to implement a joint zero-emission bus demonstration project. Electric trolley buses shall not qualify as zero-emission buses for purposes of this joint demonstration project. No more than three transit agencies can participate in any one joint project. Transit agencies that are participating in a joint demonstration project shall:

~~(A)~~1. designate the agency hosting the onsite demonstration,
~~(B)~~2. jointly fund the demonstration project, and
~~(C)~~3. place a minimum of three zero-emission buses per demonstration project in revenue service.

(2) *Advanced Demonstration Project.*

(A) Except as provided in (G) and (H) below, the owner or operator of an urban bus fleet in accordance with the provisions of section 2023.1, with more than 200 urban buses in active service on January 1, 2007, for transit agencies on the diesel path, and January 1, 2008, for transit agencies on the alternative fuel path, shall implement an Advanced Demonstration Project. The owner or operator shall evaluate the operation of zero –emission buses in revenue service, prepare and submit a report on the demonstration project to the Executive Officer.

(B) Alternative fuel path transit agencies may choose one of three following options:
1. Follow the single or joint path demonstration as described in 2023.3 (2) (D) of this section,
2. Follow the single or joint path demonstration with no more than half of the required zero emission buses converted to the zero emission enabling option as described in 2023.3 (2) (H) of this section,
3. Opt out of the advanced demonstration project and align their purchase requirement dates with the diesel path transit agencies. Notification of this option must be received in writing on January 1, 2008.

(C) A diesel fuel path transit agencies may choose to follow the single or joint path demonstration as described in 2023.3 (2) (D).

(D) Transit agencies choosing to participate in a single transit agency Advanced Demonstration Project, shall meet all of the following specifications and requirements:
1. Utilize a minimum of six zero-emission buses, or alternative fuel path transit agencies may opt to include zero emission enabling buses as set forth in section 2023.3 (H),
2. Provide appropriate maintenance and storage facilities,
3. Train bus operators and maintenance personnel,
4. Place the buses in revenue service for a minimum duration of 12 calendar months after delivery of all demonstration buses,
5. Retain operation and maintenance records, and
6. Report on the demonstration program as set forth in subdivision (f) of section 2023.4, title 13 CCR.

(E) When planning and implementing the Advanced Demonstration Project for transit agencies on the diesel path, the operator or owner shall meet the following milestones:
1. No later than January 1, 2009, place at least six zero emission buses in operation,
2. No later than July 1, 2009, submit a preliminary report on the demonstration project to the Executive Officer, in accordance with paragraph (f)(3) of section 2023.4, title 13, CCR, and
3. Submit a report no later than January 1, 2010, on the demonstration project to the Executive Officer, in accordance with paragraph (f) (4) of section 2023.4 title 13 CCR.

(F) When planning and implementing the Advanced Demonstration Project for transit agencies on the alternative-fuel path, the operator or owner shall meet the following milestones:

1. No later than January 1, 2010, place at least six zero emission buses in operation.
2. No later than July 1, 2010, submit a preliminary report on the demonstration project to the Executive Officer, in accordance with paragraph (f)(3) of section 2023.4 title 13 CCR.
3. Submit a report no later than January 1, 2011, on the demonstration project to the Executive Officer, in accordance with paragraph (f)(4) of section 2023.4 title 13 CCR.

(G) Multiple transit agencies may, on a case-by-case basis, petition the Executive Officer to implement a joint zero emission bus demonstration project. Transit agencies that are participating in a joint demonstration project shall:
1. Jointly fund the demonstration project.
2. Utilize a minimum of 12 zero emission buses in revenue service, or alternative fuel path transit agencies my opt to include zero emission enabling buses as set forth in section 2023.3(b)(H).
3. Operate the demonstration at a transit agency affected by the zero emission bus regulation.
4. Purchase and put in revenue service a minimum of three zero emission buses per transit agency.
5. Place the buses in revenue service for a minimum duration of 12 calendar months after delivery of all demonstration buses.
6. Provide appropriate maintenance and storage facilities
7. Train bus operators and maintenance personnel from each participating transit agency.

(H) Zero emission enabling buses must meet following criteria
1. The purpose of the zero emission enabling bus demonstration is to demonstrate low emission technologies and zero emission enabling technology simultaneously
2. Buses must have been certified or are in the process of being certified by the ARB to meet the applicable 2010 engine emission standards.
3. Must present data that demonstrates that the engine emissions are at or below 50% of the applicable 2010 standard.
4. Must operate on a fuel or a blend containing a fuel that is used in a zero emission bus.
5. The Executive Officer may, if presented with appropriate data, determine another advanced technology to be certifiable as a zero emission enabling bus.
6. Only applicable during the advanced demonstration.
7. Zero emission enabling buses shall replace zero emission buses by at least a three to one ratio.

8. Zero emission enabling buses do not qualify as zero emission buses or earn credits towards the purchase requirement.
9. Transit agencies must submit a plan by January 1, 2008, to the Executive Officer detailing the number and technology of the zero emission enabling buses and expected emission levels. The manufacturer(s) of the zero emission enabling buses must have a viable and complete application submitted for the verification/certification process as described in section 1956.8.

(c) ~~Purchase Requirement for Zero-emission Buses -~~ *Purchase Requirement for Zero-Emission Buses.* The owner or operator of a transit agency with more than 200 urban buses in active service on January 1, 2007, for transit agencies on the diesel path, and January 1, 2009, for transit agencies on the alternative-fuel path, shall purchase and/or lease zero-emission buses, in accordance with the following paragraphs. In addition, the status of transit agencies shall be reviewed annually starting in 2009 in accordance with section 2023.3(d).

(1) For transit agencies on the diesel path, in accordance with the requirements in section 2023.1, a minimum 15 percent of purchase and lease agreements, when aggregated annually, for model year ~~2008~~ 2011 through model year ~~2015~~ 2026 urban buses shall be zero-emission buses as per 2023.4 (g).

(2) For transit agencies on the alternative-fuel path, in accordance with the requirements in section 2023.1, a minimum 15 percent of purchase and lease agreements, when aggregated annually, for model year ~~2010~~ 2011 through model year ~~2015~~ 2026 urban buses shall be zero-emission buses as per 2023.4 (g).

(3) The provisions of paragraphs (1) and (2) shall not apply if the operator's urban bus fleet is composed of 15 percent or more zero-emission buses on January 1, 2008, for transit agencies on the diesel path, and on January 1, 2010, for transit agencies on the alternative-fuel path, or at any time thereafter.

(4) ~~(A)~~*Earning Credits*

(A) Transit agencies on either the diesel path or alternative-fuel path may earn credits for use in meeting the purchase requirements for zero-emission buses specified in paragraphs (c)(1) and (c)(2) by placing zero-emission buses in service prior to the dates specified in paragraphs (c)(1) and (c)(2). For each zero-emission bus placed into early service and above what is required by section 2023.3 in paragraphs (b)(2), (c)(1) and (c)(2), credits shall be accrued according to the following table. Each earned credit is equivalent to one zero-emission bus.

Path	Credits per Year Placed					
	~~2000-~~ 200~~3~~7	~~2004-~~ 200~~5~~8	200~~6~~9	200~~7~~10	200~~7~~11	~~2009~~
Diesel	~~3~~2.5	~~2.5~~2	~~2~~1.5	1.5	-	-
Alternative -fuel	~~3~~2.5	~~2.5~~2	2	1.5	1.5	~~1~~

(B) Zero-emission buses placed in service to meet the zero-emission bus initial demonstration projects as specified in subdivision (b)(1) are not permitted to accrue credits towards the zero-emission bus purchase requirements, unless upgraded with technology advancements to make them comparable to vehicles available for the advanced demonstration. One credit shall be earned for each bus.

(C) Zero-emission buses placed in service to meet the advanced demonstration projects as specified in subdivision (b)(2) can accrue purchase credit towards the zero emission purchase requirements. For each zero emission bus required by the advanced demonstration, credit shall be accrued according to the following table. Each earned credit is equivalent to one zero emission bus.

Path	Credits per Year Placed for Advanced Demonstration Zero Emision Buses			
	2007	2008	2009	2010
Diesel	2	1.5	1	1
Alternative Fuel	2	1.5	1.5	1

(d) The Air Resources Board shall review zero-emission bus technology and the feasibility of implementing the requirements of subdivision (c) above no later than ~~January 2006~~July 2009. Based on that assessment, the ~~Board~~ Executive Officer shall decide whether to proceed with the implementation of subdivision (c) or reduce the requirements based on the following table.

	Purchase Requirement for Zero Emission Buses		
	15%	8%	2%
Purchase Cost Fuel Cell vs. Electric Trolley Bus	1.25 : 1	1.75 : 1	3 : 1
Fuel Cell Durability or Warranty	20,000 hours	15,000 hours	3,000 hours
Reliability (Miles between Propulsion Related Road Calls) or Availability for Service (%)*	10,000 miles or 80%	7,500 miles or 70%	4,000 miles or 60%

* Only one parameter needs to be met.

NOTE: Authority cited: Sections 39600, 39601, 43013, 43018, 43100, 43101, 43104 and 43806, Health and Safety Code. Reference: Sections 39002, 39003, 39017, 39018, 39500, 39701, 40000, 43000, 43000.5, 43009, 43013, 43018, 43102, 43801 and 43806 Health and Safety Code, and section 28114 Vehicle Code.

§ 2023.4 Reporting Requirements for Transit Agencies.

(a) The following reports on new urban bus purchases and/or leases by transit agencies on the alternative-fuel path shall be submitted as described below:

(1) The initial report shall be submitted by January 31, 2001, and shall state the transit agency's intent to follow the alternative-fuel path.

(2) Any requests for deviation from the requirement that 85 percent of buses purchased per year must be alternative-fuel buses must be submitted in writing and approved by the Executive Officer of the Air Resources Board 90 days prior to purchase. The written request must include the reason for requesting the deviation from the 85 percent annual purchase requirement and the transit agency's future planned alternative-fuel bus purchases.

(3) Each transit agency shall submit an annual report containing: the number, manufacturer, make, and model year of engines, and fuel used for each urban bus it currently owns or operates, urban bus purchases and/or leases beginning January 1, 2000, and annual average percentage of total urban bus purchases and/or leases that were alternative-fuel buses. The first report shall be submitted by January 31, 2001. Subsequent reports shall be submitted annually by January 31 through the year 2016. For transit agencies operating 150 or more urban buses, reports shall be submitted annually by January 31st through the year 2027.

(b) The following reports on new urban bus purchases and/or leases by transit agencies on the diesel path shall be submitted as described below:

(1) The initial report shall be submitted by January 31, 2001, and shall state the transit agency's intent to follow the diesel path.

(2) Each transit agency shall submit an annual report containing the number, manufacturer, make, and model year of engines, and fuel used for each urban bus it currently owns or operates, and urban bus purchases and/or leases beginning January 1, 2000. The first report shall be submitted by January 31, 2001. Subsequent reports shall be submitted annually by January 31 through the year 2016. For transit agencies operating 150 or more urban buses, reports shall be submitted annually by January 31st through the year 2027.

(3) A transit agency within the jurisdiction of the South Coast Air Quality Management District that chooses to change from the diesel path to the alternative fuel path in accordance with paragraph (a)(2) of section-2023.1,

title 13, CCR, must submit to the Executive Officer a letter of intent to follow the alternative fuel path no later than January 31, 2004. The letter of intent shall contain a statement certifying that the transit agency is in compliance with all provisions of the fleet rule for transit agencies on or before January 1, 2004.

(4) As set forth in section 2023.1(a)(5), transit agencies with more than 30 buses in their fleet that purchase model-years 2007 through 2009 urban buses not certified at or below 0.2 g/bhp-hr NOx emissions shall submit the following information for each urban bus purchased: the manufacturer, make, and model year of the engine of the urban bus or transit fleet vehicle retrofitted and for each diesel emission control strategy applied, the date of installation, the device's product serial number, and its Diesel Emission Control Strategy Family Name in accordance with the requirements of section 2705(g)(2), title 13, CCR. The first report shall be submitted by January 31, 2007. Subsequent reports shall be submitted annually by January 31 through the year 2016.

(c) Each transit agency shall submit the following reports on the urban bus NOx fleet average requirement:

(1) Initial documentation shall be submitted by January 31, 2001, and contain, at a minimum, the active urban bus fleet NOx emission average, and if that number exceeds the average required in subdivision (d), section 2023.1, title 13, CCR, a schedule of actions planned to achieve that average by October 1, 2002, including numbers and model years of bus purchases, retirements, retrofits, and/or repowerings, or shall indicate the intent of the transit agency to retire all model year 1987 and earlier buses in its active fleet by October 1, 2002.

(2) A final report shall be submitted by January 31, 2003, detailing the active urban bus fleet NOx emission average as of October 1, 2002, and actions, if any were needed, taken to achieve that standard, including numbers and model years of bus purchases, retirements, retrofits, and/or repowerings, or documenting the retirement of all model year 1987 and earlier buses.

(d) Each transit agency shall submit the following reports on the total diesel PM emission reduction requirements for urban buses:

(1) An initial annual report shall be submitted by January 31, 2003 and shall contain, at a minimum, the following information:

(A) number, manufacturer, make, and model year of diesel-fueled, dual-fuel, bi-fuel (except for heavy-duty pilot ignition engines), and diesel hybrid-electric engines in urban buses in the active fleet; the

PM engine certification value of each of those bus engines; the diesel PM emission total for the diesel buses in the active fleet; and the diesel PM emission total for the baseline date of January 1, 2002.

(B) For each urban bus for which a diesel emission control strategy has been applied, the device's product serial number; its Diesel Emission Control Strategy Family Name in accordance with the requirements of section 2705(g)(2), title 13, CCR; and the date of installation.

(2) Annual reports shall be submitted each year beginning January 31, 2004 and each January 31 thereafter, through 2009, and shall contain the information required in paragraphs (d)(1)(A) and (B) above plus the total percentage reduction of PM achieved from the baseline diesel PM emission total as of January 1 of each applicable year.

(e) Each transit agency shall submit the following reports for its transit fleet vehicles:

(1) An annual report of the number, manufacturer, make, and model year of engines and fuel used for each transit fleet vehicle it currently owns, leases, or operates as of January 1st of each year, beginning in 2006. The first report shall be submitted by January 31, 2006, and subsequent reports shall be submitted annually by January 31st through the year 2016.

(2) For the NOx fleet average reduction requirements set forth in section 2023.2(a):

(A) A report submitted by January 31, 2006, must contain at a minimum, the transit vehicle fleet NOx emission average. If that number exceeds the average required in section 2023.2(a)(1), the report must include a schedule of actions planned to achieve compliance by December 31, 2007.

(i) ~~(1)~~If a change to the compliance schedule occurs that results in noncompliance, the transit agency must notify the Executive Officer within 30 days.

(ii) ~~(2)~~Notification to the Executive Officer must include a revised schedule showing how the agency will be in compliance within 90 days of the schedule change that caused noncompliance.

(B) A report submitted by January 31, 2008, must contain, details of the transit fleet vehicle fleet NOx emission average as of December 31, 2007, or must document the retirement of all model year 1997 and earlier transit fleet vehicle engines by December 31, 2007.

(C) A report submitted by January 31, 2009, must contain at a minimum, the transit vehicle fleet NOx emission average. If that number exceeds the average required in section 2023.2(a)(1), the report must include a schedule of actions planned to achieve compliance by December 31, 2007.

(i) ~~(1)~~If a change to the compliance schedule occurs that results in noncompliance, the transit agency must notify the Executive Officer within 30 days.

(ii) ~~(2)~~Notification to the Executive Officer must include a revised schedule showing how the agency will be in compliance within 90 days of the schedule change that caused noncompliance.

(D) A final report submitted by January 31, 2011 must contain details the transit fleet vehicle fleet NOx emission average as of December 31, 2010, or must document the retirement of all model year 2001 and earlier transit fleet vehicle engines by December 31, 2010.

(3) For the total diesel PM reduction requirements set forth in section 2023.2(b):

(A) An initial report submitted by January 31, 2006, must contain the PM engine certification value of each transit fleet vehicle engine and the transit fleet vehicle diesel PM total as of January 1, 2005.

(B) A report submitted by January 31, 2008, must contain the transit fleet vehicle diesel PM total as of December 31, 2007, and the percentage diesel PM reduced, documenting compliance with the requirement in section 2023.2(b)(1).

(C) A final report submitted by January 31, 2011, of the transit fleet vehicle diesel PM total as of December 31, 2010, and the percentage diesel PM reduced, documenting compliance with the requirement in section 2023.2(b)(2).

(D) For each transit fleet vehicle for which a diesel emission control strategy has been applied, each report specified above must include the strategy's product serial number; its Diesel Emission Control Strategy Family Name in accordance with the requirements of section 2705(g)(2), title 13, CCR; and the date of installation correlated to a specific transit fleet vehicle engine.

(f) The following reports on the zero-emission bus demonstration program shall be submitted by those transit agencies required to conduct such demonstrations, as described below:

(1) Initial documentation shall be submitted by January 31, 2003, and contain, at a minimum, the bus order and delivery schedule, fuel type,

type of refueling station, any planned facility modifications, and a revenue service demonstration plan;

(2) A financial plan shall be submitted by January 31, 2003, and contain, at a minimum, projected expenditures for capital costs for purchasing and/or leasing buses, refueling stations, any facility modifications, and projected annual operating costs;

(3) A preliminary report shall ~~be submitted by July 31, 2005 and~~ contain, at a minimum, the following information:

(A) a brief description of the zero-emission technology utilized, identification of the bus manufacturer, and the product specifications;

(B) miles driven per bus in revenue and non-revenue service, safety incidents, and maintenance (both scheduled and unscheduled);

(C) qualitative transit personnel and passenger experience; and

(D) a financial summary of the capital costs of bus purchases and/or leases and fueling infrastructure.

(4) A final report shall ~~be submitted by July 31, 2007, and~~ contain, at a minimum, the following information:

(A) a brief description of the zero-emission technology utilized, identification of bus manufacturer and product specifications,

(B) miles driven per bus in revenue service, <u>miles between propulsion related road calls, miles between road calls,</u> bus down time (scheduled and unscheduled), safety incidents, driver and mechanic training conducted, and maintenance (both scheduled and unscheduled),

(C) qualitative transit personnel and passenger experience, and a financial summary of capital costs of demonstration program, including bus purchases and/or leases, fueling infrastructure, any new facilities or modifications, and annual operating costs.

(g) The following reports on new zero-emission bus purchases and/or leases shall be submitted by transit agencies required to purchase zero-emission buses as described below:

(1) ~~Initial report shall be submitted by January 1, 2007 for transit agencies on the diesel path, and by January 1, 2009, for transit agencies on the alternative-fuel path.~~ The initial report shall contain, at a minimum, the following information:

(A) a brief description of the zero-emission technology to be utilized and a plan for the implementation of the requirement,

(B) for an exemption from the purchase requirement, documentation that 15 percent or more of the transit agency's active urban bus fleet is composed of zero-emission buses.

(2) Any requests for deviation from the requirement that 15 percent of buses purchased per year must be zero-emission buses must be submitted in writing and approved by the Executive Officer of the Air Resources Board 90 days prior to a transit agency submitting a purchase order(s) reflecting the purchase deviation. The written request shall include the reason for requesting the deviation and the transit agency's future planned zero-emission bus purchases.

(3) Transit agencies on the diesel path shall include in the annual reports required in paragraph (b)(2): zero-emission bus purchases and/or leases beginning with model year 2008 and through model year ~~2015~~2026, and the annual average percentage of total bus purchases and/or leases that were zero-emission buses.

(4) Transit agencies on the alternative-fuel path shall include in the annual reports required in paragraph (a)(3): zero-emission bus purchases and/or leases beginning with model year 2008~~2010~~ and through model year ~~2015~~2026, and the annual average percentage of total bus purchases and/or leases that were zero-emission buses.

(h) Transit agencies exempted from the requirements of paragraphs (b)(5) and (c)(4), section 2023.1, title 13, CCR, shall submit annual reports demonstrating that they are achieving NOx emission benefits required in paragraphs (b)(8)(B) and (c)(7)(B), section 2023.1, title 13, CCR. The first report shall be submitted by January 31, 2005. Subsequent reports shall be submitted annually by January 31 through the year 2016.

(i) A transit agency requesting approval for the purchase of diesel-fueled hybrid-electric buses pursuant to paragraph (c)(9), section 2023.1, title 13, CCR, shall:

(1) submit an application for approval that meets the requirements of paragraphs (c)(9)(A) and (c)(9)(B), section 2023.1, title 13, CCR;

(2) include in the application all of the following: the number, manufacturer, make and model year of diesel-fueled hybrid-electric buses to be purchased; the schedule for the purchase and delivery of the buses; a detailed description of all measures that will be used to offset the excess NOx emissions including identification of the specific buses to which the measures will be applied, and the schedule for implementing those measures; and

(3) submit a final report to the Executive Officer within 30 days of receipt of the last diesel-fueled hybrid-electric bus that documents the schedule of delivery of the diesel-fueled hybrid-electric buses, timing, and completion of all measures to achieve the NOx offset.

(j) A new transit agency shall submit the following information to the Executive Officer:

(1) within 60 days of formation, the name of the new transit agency, its mailing address, name of a contact person and that person's e-mail address and phone number; a description of the service area and proposed routes; and the planned number of urban buses and transit fleet vehicles, including model years of engines;

(2) within 120 days of formation, its NOx fleet average for its active fleet and, separately, its transit fleet vehicles, and its diesel PM emission total for its active fleet and , separately, its diesel PM emission total for its transit fleet vehicles.

(k) ~~(1)~~Failure to submit complete reports

(1) A transit agency that fails to submit a complete report in accordance with this section is subject to civil penalties of not less than $100 per day for every day past January 31 of each reporting year through 2016. For transit agencies with more than 150 urban buses civil penalties of not less than $100 per day for every day past January 31 shall continue for each reporting year through 2027.

(2) A new transit agency that fails to submit its report or required information in accordance with this section is subject to civil penalties of not less than $100 per day for every day past the required reporting dates in section 2023.4(j).

(3) A report that does not contain all required information will not be considered complete. A report will be considered to be complete as of the date that all required information is submitted.

NOTE: Authority cited: Sections 39600, 39601, 39659 and 39667, Health and Safety Code. Reference: Sections 39667, 39700, 39701, 41510, 41511, 43000, 43000.5, 43013, 43018, 43801 and 43806 Health and Safety Code.

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER AMENDMENTS TO THE DISTRIBUTED GENERATION CERTIFICATION REGULATION

The Air Resources Board (the Board or ARB) will conduct a public hearing at the time and place noted below to consider adoption of amendments to the Distributed Generation (DG) Certification regulation.

DATE: October 19, 2006

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, CA 95814

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., October 19, 2006, and may continue at 8:30 a.m., October 20, 2006. This item may not be considered until October 20, 2006. Please consult the agenda for the meeting, which will be available at least 10 days before October 19, 2006, to determine the day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette, or computer disk. Please contact ARB's Disability Coordinator at 916-323-4916 by voice, or through the California Relay Services at 711, to place your request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at 916-323-7053.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed amendments to title 17, California Code of Regulations, sections 94201, 94201.1, 94203, 94204, 94207, 94208, 94209, 94210, 94211, and 94212.

Background:

Distributed generation refers to replacing or supplementing electricity from the grid with electrical generation sources that are located near the place of use. Some examples of electrical generation technologies are engines, turbines, fuel cells, and photovoltaic cells. Some businesses choose to operate distributed generation technologies with heat recovery systems that capture the heat produced from the electrical generation process. This captured heat can then be used to heat water, provide steam or space

heating, or power a chiller at the facility. Distributed generation can be used at various types of businesses such as hospitals, schools, libraries, breweries, utilities, and laundries.

Senate Bill (SB) 1298 (Stats. 2000, ch. 741) required the ARB to establish a distributed generation certification program for electrical generation technologies that are exempt from local air district permits. SB 1298 mandated that ARB establish at least two levels of emission standards for affected DG technologies. The law required that the first set of standards be effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permits. The law also required that, by the earliest practicable date, the standards be made equivalent to the level determined by ARB to be the best available control technology (BACT) for permitted central station power plants in California. The emission standards were to be expressed in pounds per megawatt hour (lb/MW-hr) to reflect the efficiencies of various electrical generation technologies.

Pursuant to SB 1298, the Board adopted a DG Certification regulation in 2001. The ARB staff proposed interim standards for 2003 and recommended that 2007 be considered the earliest practicable date for DG applications to meet central power plant emissions standards. In addition to establishing emission standards, the DG Certification regulation included testing protocols, calculation procedures, and other specified requirements that manufacturers must satisfy to certify DG technologies.

Generally, microturbines up to 250 kilowatts (kW), engines less than 50 horsepower (hp), and fuel cells are exempt from district permits. Although small engines are exempt from district permits, most engines used in distributed generation applications are larger than district permit exemption levels and therefore require district permits. Consequently, the regulation has so far only affected fuel cells and microturbines. These types of technologies were just entering the California market when the Board adopted the DG Certification regulation in 2001.

Because of uncertainties at the time regarding the development and deployment of these DG technologies, the regulation includes a requirement for a technology review within a few years to evaluate the status of the DG certification program and determine if revisions were warranted. The technology review was to address the feasibility of the 2007 standards, the credit given for utilizing combined heat and power (CHP)* to meet these standards, emissions durability, and test methods and procedures. Evaluating these specific requirements was the primary focus of ARB staff's evaluation; however, ARB staff also evaluated other additions and changes to the regulation during the review. Staff's proposed amendments are a result of that review process.

* Combined heat and power (CHP) refers to the total amount of useful energy obtained from the DG equipment. It is the sum of the electrical output of the unit plus the amount of waste heat utilized in a productive manner, such as heating water or providing heat to industrial processes. These combined energy outputs are used to calculate the total megawatt-hours produced, and are therefore used when determining the emissions in pounds per megawatt-hour.

DESCRIPTION OF THE PROPOSED REGULATORY ACTION

Emissions Durability and Testing Requirements

The proposed amendments would require manufacturers of DG units, when preparing the application package, to identify key components of the DG unit that are most critical to ensuring compliance with the certified emission limits, such as fuel injectors, rotors, seals and bearings for a microturbine, and fuel cell stacks and catalysts for fuel cells. In addition, the manufacturer would be required to keep records relating to how often these components are replaced and submit the records to ARB upon request. In this manner, ARB staff will be able to track durability of equipment in the field.

Staff is proposing a number of changes to the testing requirements and parameters to improve and clarify the testing requirements and better reflect actual in-the-field operations of affected technologies. The proposed amendments would require manufacturers to test at only 100 percent load versus the three-load testing that is currently required because staff has determined that certified DG technologies are generally operated at only full capacity in the field. VOC testing would now be conducted using South Coast Air Quality Management District test method 25.3 to more accurately measure emissions at the low concentrations expected from certified technologies. To reduce recordkeeping and testing requirements for the manufacturers, they would no longer be required to test each individual DG unit for NOx emissions prior to commercial use. For clarification purposes, manufacturers would now be required to use a specific method to calculate recoverable heat if a CHP credit is being used to meet a standard. And, finally, the generator output measured during the source test would be based on net power output, not the gross output of the unit, to more accurately represent the actual available power from the unit.

Addition of Waste Gas Emission Standards

The proposed amendments would add requirements to enable technologies fueled with waste gases (landfill, digester, and oil-field waste gases) to be certified under this program. The current regulation, although allowing for fuels other than natural gas to be used for certification, does not contain a practical method in which to accomplish this. The composition of waste fuels varies from site to site and season to season, which makes it challenging to issue statewide certifications on these variable fuels. Therefore, local air districts have had to issue permits to otherwise permit-exempt equipment. The ARB staff proposes to bring these waste-gas applications into the DG certification program where they appropriately belong. Both the local air districts and the manufacturers support integrating waste gas applications into the certification program.

To certify these permit-exempt waste-gas applications, ARB staff has developed surrogate fuel compositions based on data submitted to the ARB for landfill gases, digester gases, and oil-field waste gases. Manufacturers would be required to use these surrogate gases for certification testing.

Staff is proposing two sets of waste gas standards, much like what is currently in the regulation. Staff is proposing 2008 interim waste-gas standards that are similar to the current 2003 limits. Unlike the 2003 standards, the waste-gas 2008 standards would not include a particulate matter (PM) standard nor would they include a separate, less stringent, set of limits for units integrated with CHP. A PM standard is not being proposed because the impurities in waste gas that would contribute to PM emissions will be removed prior to being used with DG units in the field. Staff is not proposing to include less stringent 2008 limits for units integrated with CHP because manufacturers would now only have to test at 100 percent power load, which should allow them to meet the more stringent limits.

The proposed 2013 waste-gas standards are identical to the current 2007 limits, except for the omission of a PM standard as described above. The 2013 standards reflect central station power plant emissions, as required in SB 1298. As with the 2007 standards, a manufacturer can use a CHP credit to meet the 2013 standards if the unit is integrated and sold with a heat recovery system and can achieve a minimum overall efficiency of 60 percent. The proposed waste-gas emission standards are presented in Table 1.

Table 1: Proposed Waste Gas Emission Standards

Pollutant	Emission Standard (lb/MW-hr)	
	On or after January 1, 2008	On or after January 1, 2013
NO_x	0.5	0.07
CO	6.0	0.10
VOCs	1.0	0.02

Other Amendments

The proposed amendments would clarify that the current 2007 standards apply only to natural gas and liquefied petroleum gas (LPG) units and would define LPG. In addition, staff proposes elimination of the PM standard in the current 2007 emission standards because staff has determined that it is unnecessary for these gaseous fuels to have a PM standard.

The proposed amendments would change the fee structure of the program to fully cover costs to the State to implement this program, as allowed by SB 1298. Initial certification application fees under the proposed amendments would increase $5,000 from $2,500 to $7,500 to better reflect the average 60 hours the ARB staff has needed to review and process certification applications to date.

To provide an economic incentive for early introduction of the cleanest waste-gas-fueled DG technologies, manufacturers of technologies that can meet the 2013 standards by January 1, 2008 (such as fuel cells), would be exempt from submitting an initial application fee.

The current fee assessment for recertification is $2,500. The ARB staff proposes maintaining that fee for DG units that do not require a source test for recertification but assessing a fee of $7,500 for DG units that require a source test for recertification. These fees are based on staff time estimates of about 20 hours for applications that do not contain source test results, and about 60 hours to process applications that do contain source test results.

Currently, applicants seeking voluntary certification for DG technologies that do not emit an air contaminant are not charged any application fee. The ARB staff proposes that a fee of $2,500 be assessed for manufacturers seeking voluntary certification. To date, ARB has not received any applications for voluntary certifications.

Since the waste-gas emission standards are five years apart (2008 and 2013) ARB staff is proposing that certifications issued to units meeting the 2008 standards on waste gas be valid for five years or to January 1, 2013, whichever comes first. For consistency, staff is proposing expansion of the duration of certifications based on the 2007 natural-gas standards from four years to five years as well.

ARB staff is proposing expansion of the allowable exemptions to the regulation to include units operated by the manufacturer for quality assurance testing, and units that are part of a research operation that the Executive Officer has approved. Staff is also proposing a clarification that all portable electrical generation technologies are exempt from this program, not just those that are registered in ARB's Portable Equipment Registration Program. These other portable DG units are already regulated under other ARB and United States Environmental Protection Agency (U.S. EPA) programs.

ARB staff is proposing the Board modify the inspection and enforcement provisions in the regulation, modify and add terms in the definitions section, and make other editorial changes throughout the regulation. These changes are considered to be non-substantive and are intended to improve and clarify the DG Certification regulation.

COMPARABLE FEDERAL REGULATIONS

The certification program that staff is proposing to the Board amend is not required by federal law or regulation. There are no comparable federal regulations covering the certification of emissions from small DG technologies.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

The Board staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The report is entitled: "Staff Report: Initial Statement of Reasons for the Proposed Amendments to the Distributed Generation Certification Regulation."

Copies of the ISOR and the full text of the proposed regulatory language, in underline and strikeout format to allow for comparison with the existing regulations, may be accessed on the ARB's web site listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990 at least 45 days prior to the scheduled hearing on October 19, 2006.

Upon its completion, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on the ARB's web site listed below.

Inquiries concerning the substance of the proposed amendments may be directed to the designated agency contact persons: Michael Waugh, Manager of the Program Assistance Section, Project Assessment Branch, Stationary Source Division at (916) 445-6018, and Dave Mehl, Air Resources Engineer, Stationary Source Division at (916) 327-1512.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Artavia Edwards, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-6070, or Alexa Malik, Regulations Coordinator, (916) 322-4011. The Board has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on the ARB Internet site for this rulemaking at www.arb.ca.gov/regact/dg06/dg06.htm.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulations are presented below.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action will not create costs or savings to any State agency or in federal funding to the State, costs or mandate to any local agency or school district whether or not reimbursable by the state pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, or other nondiscretionary cost or savings to State or local agencies.

In developing this regulatory proposal, the ARB staff evaluated the potential economic impacts on representative private persons or businesses. The ARB staff has identified six manufacturers that will potentially be impacted by the proposed amendments: the same manufacturers who have already certified their units on natural gas. The overall

statewide cost of the proposed amendments is estimated to be $1,800,000, with an estimated individual business cost of $135,000 to $158,000 for each DG model certified (assuming each unit is certified to operate on three waste gas fuels). Businesses will incur costs for conducting an emissions source test on each DG model and waste-gas fuel type to be certified, preparing and submitting a certification application, and paying an application fee.

The ARB staff does not expect complying with the proposed waste-gas standards to cause adverse economic impacts on businesses. ARB staff believes that both fuel cells and microturbines operating on waste gases can currently meet the proposed 2008 standards. Manufacturers should not incur significant adverse economic impacts from complying with the proposed 2013 waste-gas emission standards, as these standards are similar to the 2007 standards with which manufacturers must currently comply for their natural-gas-fueled units. ARB staff believes that fuel cells can currently meet the 2013 standards on waste gases, but that microturbines will need more time to achieve these standards on waste gases. Although the January 1, 2013, compliance date will give manufacturers five years to research and develop new products to meet central station emission limits with waste gases, much of the research and development effort needed to meet the 2013 standards will have already been spent on achieving the 2007 natural gas standard.

The Executive Officer has made an initial determination that the proposed regulatory action will not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons.

In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action will not affect the creation or elimination of jobs within the State of California, the creation of new businesses or elimination of existing businesses within the State of California, or the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the ISOR.

The Executive Officer has also determined, pursuant to title 1, CCR, section 4, that the proposed regulatory action will affect small businesses. The ARB staff has identified two out of the six manufacturers that will potentially be impacted by the proposed amendments as small businesses. Both small businesses manufacture fuel cell technologies; however, neither company is in California. These businesses should incur costs of $135,000 for each DG unit certified to comply with the proposed 2013 waste-gas standards.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board or that has otherwise been identified and brought to the attention of the Board would be more effective in carrying out the purpose for which the action is proposed or would be as effective and less burdensome to affected private persons than the proposed action.

SUBMITTAL OF COMMENTS

The public may present comments relating to this matter orally or in writing at the hearing, and in writing or by e-mail before the hearing. To be considered by the Board, written submissions not physically submitted at the hearing must be received **no later than 12:00 noon, October 18, 2006**, and addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal : http://www.arb.ca.gov/lispub/comm/bclist.php

Facsimile submittal: (916) 322-3928

The Board requests but does not require that 30 copies of any written statement be submitted and that all written statements be filed at least 10 days prior to the hearing so that ARB staff and Board Members have time to fully consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under that authority granted in Health and Safety Code, sections 39600, 39601 and 41514.9. This action is proposed to implement, interpret, and make specific section 41514.9.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non-substantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action; in such event the full regulatory text, with the modifications clearly indicated, will be made available to the public, for written comment, at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from the ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990.

CALIFORNIA AIR RESOURCES BOARD

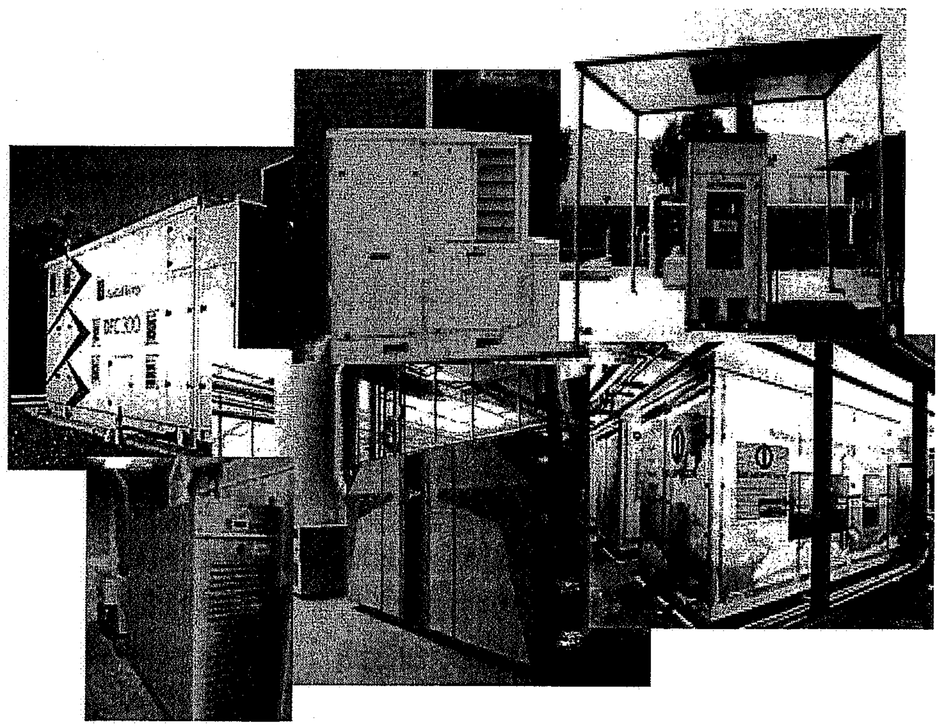
Michael W. Scheible

for Catherine Witherspoon
Executive Officer

Date: August 22, 2006

California Environmental Protection Agency
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED AMENDMENTS TO THE DISTRIBUTED GENERATION CERTIFICATION REGULATION



Stationary Source Division
Project Assessment Branch

September 1, 2006

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

Public Hearing to Consider

Proposed Amendments to the Distributed Generation Certification Regulation

To be considered by the Air Resources Board on October 19, 2006, at:

California Environmental Protection Agency
Headquarters Building
1001 I Street
Byron Sher Auditorium
Sacramento, California

STATIONARY SOURCE DIVISION

Robert Fletcher, Chief
Robert D. Barham, Assistant Chief
Michael J. Tollstrup, Chief, Project Assessment Branch
Michael Waugh, Manager, Program Assistance Section

State of California
AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE DISTRIBUTED GENERATION CERTIFICATION REGULATION

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Acknowledgements

This report was prepared with the assistance and support form the other divisions and offices of the Air Resources Board. In addition, we would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations.

Staff Report: Initial Statement of Reasons for the Proposed Amendments to the Distributed Generation Certification Regulation

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Appendices

EXECUTIVE SUMMARY

A. INTRODUCTION

This Executive Summary outlines the Air Resources Board (ARB or Board) staff's proposal to amend the Distributed Generation (DG) Certification regulation, which was approved by the Board on November 15, 2001.

This report comprises the Initial Statement of Reasons for the Proposed Amendments to the DG Certification regulation as required by the Administrative Procedures Act (Government Code 11340 et seq.). The Executive Summary of this report provides an overview of the proposed amendments to the DG Certification regulation, a summary of staff recommendations, and a brief discussion of the environmental and economic impacts resulting from the proposal. The body of the report provides a more detailed presentation of the technical aspects of the proposed amendments to the DG Certification regulation.

B. BACKGROUND

Distributed generation refers to replacing or supplementing electricity from the grid with electrical generation sources that are located near the place of use. Some examples of electrical generation technologies are engines, turbines, fuel cells, and photovoltaic cells. Some businesses choose to operate distributed generation technologies with heat recovery systems that capture the heat produced from the electrical generation process. This captured heat can then be used to heat water, provide steam or space heating, or power a chiller at the facility. Distributed generation can be used at various types of businesses such as hospitals, schools, libraries, breweries, utilities, and laundries.

Senate Bill (SB) 1298 (chaptered in 2000) required the ARB to establish a distributed generation certification program for electrical generation technologies that are exempt from local air district permits. SB 1298 mandated that the ARB establish at least two levels of emission standards for affected DG technologies. The law required that the first set of standards be effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permits. The law also required that, by the earliest practicable date, the standards be made equivalent to the level determined by the ARB to be the best available control technology (BACT) for permitted central station power plants in California. The emission standards were to be expressed in pounds per megawatt hour (lb/MW-hr) to reflect the efficiencies of various electrical generation technologies.

Pursuant to SB 1298, the Board adopted a DG Certification regulation in 2001. The ARB staff proposed interim standards for 2003 and recommended that 2007 be considered the earliest practicable date for DG applications to meet central power plant emission standards. In addition to establishing emission standards, the DG Certification regulation included testing protocols, calculation procedures, and other specified requirements that manufacturers must satisfy to certify DG technologies.

Generally, microturbines up to 250 kilowatts (kW), engines less than 50 horsepower (hp), and fuel cells are exempt from district permits. Although small engines are exempt from district permits, most engines used in distributed generation applications are larger and therefore require district permits. Consequently, the regulation has so far only affected fuel cells and microturbines.

There are currently about 700 microturbines and fuel cells in California capable of producing more than 41 MW of electricity. Of the 700 units, only four percent are fuel cells. Roughly half of the 700 units are certified models using natural gas. Of the remaining, there are more than 100 units operating on natural gas that were purchased before the DG Certification program became effective in 2003. The final 200 units operate on waste-gas fuels and are permitted by the local air districts. Roughly 50 percent of the certified units using natural gas operate with a heat recovery system. This is not surprising. To be economically competitive with grid power, DG units using natural gas should have a significant demand for the waste heat generated for such processes as heating water or running an absorption chiller.

Microturbines and fuel cells were just entering the California market when the Board adopted the DG Certification regulation in 2001. Because of uncertainties at the time regarding the development and deployment of these DG technologies, the ARB staff included in the regulation a requirement to conduct a technology review within a few years to evaluate the status of the DG certification program and determine if revisions were warranted. Staff's proposed amendments are a result of that review process.

C. PUBLIC PROCESS

In developing any regulation, the public, local air districts, and affected industries play an important role in shaping the regulatory proposals. ARB staff has made extensive efforts to have an open process and provide ample opportunity for input by all parties.

A DG workgroup was formed to assist ARB staff with conducting the 2005 technology review and developing the amendments to the DG Certification regulation. The workgroup consisted of approximately thirty individuals representing manufacturers of DG technologies, environmental groups, the California Energy Commission, utility companies, local air districts, and other interested parties. The ARB staff held the first workgroup meeting on

June 2, 2004, in Sacramento, and convened workgroup meetings intermittently for two years while developing draft amendments to the DG Certification regulation. Staff presented draft proposed amendments at a public consultation meeting on July 6, 2006, to invite discussion and comment by stakeholders and the public.

The ARB staff has maintained a website to facilitate the dissemination of up-to-date information on the progress of the modifications to the DG Certification regulation. The website is located at http://www.arb.ca.gov/energy/dg/dg.htm. In addition, ARB staff also used an e-mail list serve to notify affected industries and other interested parties of the workgroup meetings, agendas, and information to be discussed at the meetings. Approximately 1,200 individuals from federal, state, and local government, environmental groups, and industry subscribe to the list serve.

Staff participated in numerous individual meetings and conference calls with affected industry and other stakeholders to discuss and resolve issues specific to the proposed amendments. Staff also held conference calls with source testing representatives and manufacturers to discuss specific testing issues.

Staff revised the proposed amendments to the DG Certification regulation in consideration of the comments received during the public process. Staff made every effort to consider all comments and recommendations received.

D. PURPOSE OF TECHNOLOGY REVIEW

The certification regulation required the ARB staff to conduct a technology review by July 2005 to evaluate if specific certification requirements should be modified. ARB staff committed to this review because at the time the regulation was adopted, the technologies that would be affected by the regulation had not yet entered or were just entering the California market. Very little information was available on these emerging technologies.

The technology review was to address the feasibility of the 2007 standards, the credit given for utilizing combined heat and power (CHP)* to meet these standards, emissions durability, and test methods and procedures. Evaluating these specific requirements was the basis of ARB staff's evaluation; however, ARB staff also evaluated other additions and changes to the regulation during the review. Based on staff's evaluation of data available today, no changes are being proposed to the compliance date for the 2007 limits or to the CHP credit a manufacturer can use to meet these limits. Staff has identified necessary

* Combined heat and power (CHP) refers to the total amount of useful energy obtained from the DG equipment. It is the sum of the electrical output of the unit plus the amount of waste heat utilized in a productive manner, such as heating water or providing heat to industrial processes. These combined energy outputs are used to calculate the total megawatt-hours produced, and are therefore used when determining the emissions in pounds per megawatt-hour.

changes to the emissions durability and testing requirements. The next section discusses these proposed changes along with other proposed modifications needed to improve the program.

E. SUMMARY OF THE PROPOSED AMENDMENTS TO THE DISTRIBUTED GENERATION CERTIFICATION REGULATION

1. Emissions Durability and Testing Requirements

The proposed amendments would require manufacturers, when preparing the application package, to identify key components of the DG unit that are most critical to ensuring compliance with the certified emission limits, such as fuel injectors, rotors, seals and bearings for a microturbine, and fuel cell stacks and catalysts for fuel cells. In addition, the manufacturer would be required to keep records relating to how often these components are replaced and submit the records to the ARB upon request. In this manner, ARB staff will be able to track durability of equipment in the field.

Staff is proposing a number of changes to the testing requirements and parameters to improve and clarify the testing requirements and better reflect actual in-the-field operations of affected technologies. The proposed amendments would require manufacturers to test at only 100 percent load versus the three-load testing that is currently required because staff has determined that certified DG technologies are generally operated at only full capacity in the field. VOC testing would now be conducted using South Coast Air Quality Management District test method 25.3 to more accurately measure emissions at the low concentrations expected from certified technologies. To reduce recordkeeping and testing requirements for the manufacturers, they would no longer be required to test each individual DG unit for NOx emissions prior to commercial use. For clarification purposes, manufacturers would now be required to use a specific method to calculate recoverable heat if a CHP credit is being used to meet a standard. And, finally, the generator output measured during the source test would be based on net power output, not the gross output of the unit, to more accurately represent the actual available power from the unit.

2. Addition of Waste Gas Emission Standards

The proposed amendments would add requirements to enable technologies fueled with waste gases (landfill, digester, and oil-field waste gases) to be certified under this program. The current regulation, although allowing for fuels other than natural gas to be used for certification, does not contain a practical method in which to accomplish this. The composition of waste fuels varies from site to site and season to season, which makes it challenging to issue statewide certifications on these variable fuels. Therefore, local air districts have had to issue permits to otherwise permit-exempt equipment. The ARB staff proposes to bring these waste-gas applications into the DG certification program where they appropriately belong. Both the local air districts and the manufacturers support integrating waste gas applications into the certification program.

To certify these permit-exempt waste-gas applications, ARB staff has developed surrogate fuel compositions based on data submitted to the ARB for landfill gases, digester gases, and oil-field waste gases. Manufacturers would be required to use these surrogate gases for certification testing.

Staff is proposing two sets of waste gas standards, much like what is currently in the regulation. Staff is proposing 2008 interim waste-gas standards that are similar to the current 2003 limits. Unlike the 2003 standards, the waste-gas 2008 standards would not include a particulate matter (PM) standard nor would they include a separate, less stringent, set of limits for units integrated with CHP. A PM standard is not being proposed because the impurities in waste gas that would contribute to PM emissions will be removed prior to being used with DG units in the field. Staff is not proposing to include less stringent 2008 limits for units integrated with CHP because manufacturers would now only have to test at 100 percent power load, which should allow them to meet the more stringent limits.

The proposed 2013 waste-gas standards are identical to the current 2007 limits, except for the omission of a PM standard as described above. The 2013 standards reflect central station power plant emissions, as required in SB 1298. As with the 2007 standards, a manufacturer can use a CHP credit to meet the 2013 standards if the unit is integrated and sold with a heat recovery system and can achieve a minimum efficiency of 60 percent. The proposed waste-gas emission standards are presented in Table 1:

Table 1: Proposed Waste Gas Emission Standards

Pollutant	Emission Standard (lb/MW-hr)	
	On or after January 1, 2008	On or after January 1, 2013
NO_x	0.5	0.07
CO	6.0	0.10
VOCs	1.0	0.02

3. Other Amendments

The proposed amendments would eliminate the PM standard in the current 2007 emission standards, clarify that the current 2007 standards would apply to fossil fuels (e.g., natural gas and liquefied petroleum gas (LPG)) units, and add a definition for LPG.

The current 2007 PM emission standard is essentially the sulfur limit in Public Utility Commission (PUC) grade natural gas (one grain of sulfur per 100 standard cubic feet). Staff is proposing to eliminate this PM standard for natural gas because it is redundant: "natural gas" is defined in the regulation as PUC-quality gas. Staff proposes to not include a PM standard for LPG, as it is not expected to have any measurable amount of PM emissions.

The proposed amendments would change the fee structure of the program to fully cover costs to the State to implement this program, as allowed by SB 1298. Initial certification application fees under the proposed amendments would increase $5,000 from $2,500 to $7,500. Staff had estimated $2,500 per application when the DG certification program was being developed in 2001, but subsequent experience with the program has shown that staff underestimated the number of hours required to review and process certification applications. The new fee reflects the estimated 60 hours of ARB staff time that is generally needed to process applications.

Manufacturers of technologies that can meet the 2013 standards by January 1, 2008 (such as fuel cells), would be exempt from submitting an initial fee. ARB staff is proposing no initial application fee for these technologies to provide an economic incentive for early introduction of the cleanest waste-gas-fueled DG technologies.

The current fee assessment for recertification is $2,500. The ARB staff proposes to maintain that fee for DG units that do not require a source test for recertification. Staff proposes to assess a fee of $7,500 for DG units that require a source test for recertification. This fee is based on staff time estimates of about 20 hours for applications that do not contain source test results, and about 60 hours to process applications that do contain source test results.

Currently, applicants seeking voluntary certification for DG technologies that do not emit an air contaminant are not charged any application fee. The ARB staff proposes to assess a fee of $2,500 for manufacturers seeking voluntary certification. To date, ARB has not received any applications for voluntary certifications.

Since the waste-gas emission standards are five years apart (2008 and 2013) ARB staff is proposing that certifications issued to units meeting the 2008 standards on waste gas be valid for five years or to January 1, 2013, whichever comes first. For consistency, staff is proposing to expand the duration of certifications based on the 2007 fossil fuel standards from four years to five years as well.

ARB staff is proposing to expand the allowable exemptions to the regulation to include units operated by the manufacturer for quality assurance testing, and units that are part of a research operation that the Executive Officer has approved. Staff is also proposing to clarify that all portable electrical generation technologies are exempt from this program, not just those that are registered in

ARB's Portable Equipment Registration Program. These other portable DG units are already regulated under other ARB and United States Environmental Protection Agency (U.S. EPA) programs.

ARB staff is proposing to modify the inspection and enforcement provisions in the regulation, modify and add terms in the definitions section, and make other editorial changes throughout the regulation. These changes are considered to be non-substantive and are intended to improve and clarify the DG Certification regulation.

F. ENVIRONMENTAL AND ECONOMIC IMPACTS OF THE PROPOSED AMENDMENTS

1. What are the expected environmental impacts of the proposed amendments?

The proposed amendments to the DG Certification regulation will reduce emissions of NOx, CO, and VOCs from DG technologies exempt from local air district permits and used in waste-gas applications. Currently, these technologies have to obtain permits from the local air districts. Inclusion of these waste-gas applications into the DG certification program will subject the technologies to more stringent emission standards than is typically required by the local air districts, especially when considering that these technologies must meet central station power plant emission levels by 2013.

2. What are the economic impacts of the proposed amendments?

The overall statewide cost of the proposed amendments is estimated to be $1,800,000 with an estimated individual business cost of $135,000 to $158,000 for each DG model certified (assuming each unit is certified to operate on three waste gas fuels). Businesses will incur costs for conducting an emissions source test on each DG model and fuel type to be certified, preparing and submitting a certification application, and paying an application fee.

Manufacturers should not incur significant adverse economic impacts from complying with the proposed 2013 waste-gas emission standards, as these standards are similar to the 2007 standards with which manufacturers must currently comply for their natural-gas-fueled units. ARB staff believes that fuel cells can currently meet the 2013 standards, but that microturbines will need more time to achieve these standards on waste gases. The January 1, 2013, compliance date will give manufacturers five years to research and develop new products to meet central station emission limits with waste gases. Much of the research and development effort needed to meet the 2013 standards will have already been spent on achieving the 2007 natural gas standard.

G. NEXT STEPS

Upon Board approval of the proposed amendments to the DG Certification regulation, ARB staff will conduct outreach efforts with affected manufacturers regarding the new requirements and continue to implement the DG Certification program.

H. RECOMMENDATIONS

The staff recommends that the Board approve the proposed amendments to the DG Certification regulation. The amendments fulfill the technology review requirements in the regulation by addressing necessary changes to the emissions durability and testing requirements. The proposed amendments also include changes to other sections that improve the DG Certification program. Finally, the amendments ensure unpermitted waste-gas technologies conform to the intent of SB 1298 by being added to the certification program as soon as possible.

I. INTRODUCTION

In this chapter, the Air Resources Board (ARB of Board) staff provides an overview of this report, discusses the purpose of the proposed amendments (included in Appendix A), discusses the regulatory authority ARB has to adopt the proposed amendments, and discusses the outreach efforts undertaken by ARB staff while developing the proposed amendments.

A. OVERVIEW AND REGULATORY AUTHORITY

Distributed generation refers to replacing or supplementing electricity from the grid with electrical generation sources that are located near the place of use. Some examples of electrical generation technologies are engines, turbines, fuel cells, and photovoltaic cells. Some businesses choose to operate distributed generation technologies with heat recovery systems that capture the heat produced from the electrical generation process. This captured heat can then be used to heat water, provide steam, or power a chiller. Distributed generation can be used at various types of businesses such as hospitals, schools, libraries, breweries, and laundries.

Senate Bill (SB) 1298 (chaptered in 2000) required the ARB to establish a Distributed Generation (DG) certification program for electrical generation technologies that are exempt from local air district permits. The Board approved the DG Certification regulation on November 15, 2001; the regulation was effective on October 4, 2002, and was codified in Title 17, California Code of Regulations (CCR) sections 94200 to 94214.

SB 1298 (which is included in Appendix B) mandated that the ARB establish at least two levels of emission standards for affected DG technologies. The law required that the first set of standards be effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permits. The law also required that, by the earliest practicable date, the standards be made equivalent to the level determined by the ARB to be the best available control technology (BACT) for permitted central station power plants in California. The emission standards were to be expressed in pounds per megawatt hour (lb/MW-hr) to reflect the efficiencies of various electrical generation technologies. In addition to establishing emission standards, the DG Certification regulation included testing protocols, calculation procedures, and other specified requirements that manufacturers must satisfy to certify DG technologies.

The DG Certification regulation required the ARB staff to conduct a technology review by July 2005 and to address four specific issues: the feasibility of the

2007 standards, the credit given for utilizing combined heat and power (CHP[•]) to meet these standards, the test methods and procedures, and the emissions durability. Evaluating these specific requirements was the basis of ARB staff's evaluation; however, ARB staff also evaluated other additions and changes to the regulation during the review. In addition, staff is proposing to add requirements to certify units operating on waste fuels, modify recordkeeping, recertification, and fee requirements, and modify other sections of the regulation to increase the clarity and enforceability of the regulation.

This report provides:

- a discussion of certified distributed generation technologies;
- a summary of the proposed amendments to the DG Certification regulation;
- environmental and economic impacts of the proposed amendments;
- the proposed amended DG Certification regulation; and
- other supplemental information.

B. PUBLIC OUTREACH

In developing any regulation, the public, local air districts, and affected industries play an important role in shaping the regulatory proposals. The ARB staff has made extensive efforts to have an open process and provide ample opportunity for input by all parties.

The ARB staff formed a workgroup in May 2004 to seek assistance from stakeholders with conducting the 2005 technology review and developing the amendments to the DG Certification regulation. The workgroup consisted of approximately 30 individuals representing manufacturers of DG technologies, environmental groups, the California Energy Commission, utility companies, local air districts, and other interested parties. ARB staff held the first workgroup meeting on June 2, 2004, in Sacramento. Staff convened seven subsequent workgroup meetings: August 19, 2004, October 22, 2004, January 13, 2005, January 27, 2006, March 30, 2006, May 9, 2006, and June 13, 2006. Staff presented draft proposed amendments at a public consultation meeting on July 6, 2006, to invite discussion and comment by stakeholders and the public.

The ARB staff has maintained a website to facilitate the dissemination of up-to-date information on the progress of the modifications to the DG Certification regulation. The website is located at *http://www.arb.ca.gov/energy/dg/dg.htm*. In addition, ARB staff also used an e-mail list serve to notify affected industries and

[•] Combined heat and power (CHP) refers to the total amount of useful energy obtained from the DG equipment. It is the sum of the electrical output of the unit plus the amount of waste heat utilized in a productive manner, such as heating water or providing heat to industrial processes. These combined energy outputs are used to calculate the total megawatt-hours produced, and are therefore used when determining the emissions in pounds per megawatt-hour.

other interested parties of the workgroup meetings, agendas, and information to be discussed at the meetings. Approximately 1,200 individuals from federal, state, and local government, environmental groups, and industry subscribe to the list serve.

Staff participated in numerous individual meetings and conference calls with affected industry and other stakeholders to discuss and resolve issues specific to the proposed amendments. Staff also held conference calls with source testing representatives and manufacturers to discuss specific testing issues.

Staff revised the proposed amendments to the regulation in consideration of the comments received during the public process. Staff made every effort to consider all comments and recommendations received.

II. OVERVIEW OF CERTIFIED DISTRIBUTED GENERATION TECHNOLOGIES

This chapter provides an overview of DG technologies that have been certified under this program. The overview includes a discussion of the types, inventory, uses, and health benefits from certified DG units in California.

A. DESCRIPTION OF CERTIFIED DG TECHNOLOGIES

Stationary sources of air pollution are subject to permitting requirements by the local air districts. However, some stationary sources of air contaminants are exempt from permits because of their small size and/or low emission rates. Electrical generation technologies that are exempt from local air districts' permit requirements are subject to the ARB's certification program.

Permit exemption levels vary among California's 35 local air districts, although microturbines up to 250 kilowatts (kW) in size are generally exempt from district permits, as are fuel cells of any size and reciprocating engines less than 50 horsepower. Although small engines may be exempt from local air district permits, most engines used in distributed generation applications are considerably larger than 50 horsepower and therefore require district permits. Consequently, only two types of DG technologies have been certified under ARB's DG Certification program: microturbines and fuel cells. A description of these two technologies follows.

1. Microturbines

Microturbines are high-speed, single-rotor turbines that are generally 250 kW or less in size and can burn natural gas, liquified petroleum gas (LPG), or waste gases. They can operate alone or in parallel with a number of units. Five microturbine models have been certified to date: a 60-kW unit, two 70-kW units, a 100-kW unit, and a 250-kW unit.

Microturbines have been utilized in numerous DG applications. To date, about 70 percent of the microturbines in California are used with natural gas, providing power to buildings, such as schools, hospitals, and laundries. The other 30 percent have been used in waste-gas applications, with landfills outpacing digesters by two-to-one. There are some oil-field waste-gas applications as well.

2. Fuel Cells

A fuel cell is an electrochemical device that combines hydrogen with oxygen to produce electricity, heat, and water. A fuel cell consists of an anode, cathode, and electrolyte. Electrochemical oxidation and reduction reactions take place at the electrodes to produce electrical current. Each individual fuel cell produces less than one volt, so cells are stacked to obtain the desired voltage.

The hydrogen fuel can be supplied through a hydrogen tank, or, more likely, with a reformer that extracts the hydrogen from a fossil fuel, such as natural gas. There are five types of fuel cells: phosphoric acid, molten carbonate, solid oxide, alkaline, and proton exchange membrane. Five fuel cell models have been certified to date: a 5-kW proton exchange membrane unit, two 250-kW molten carbonate units, a 1-MW molten carbonate unit, and a 200-kW phosphoric acid unit.

Fuel cells, because of their expense and restrictions on fuel quality, have been used predominantly in natural gas applications, although there are a handful of digester applications. Currently, there are no landfill or oil field applications with fuel cells.

B. INVENTORY OF DG TECHNOLOGIES

When the Board adopted the DG Certification regulation in 2001, the types of DG technologies expected to be subject to certification were just entering the California market. It was unclear as to where these units would ultimately be placed or what type of fuel they would use.

The ARB staff surveyed the six manufacturers with certified equipment and asked them to inventory their DG units located in California by model, fuel type, and usage of combined heat and power (CHP). The fuel types listed in the survey were natural gas, LPG, oil-field waste gas, landfill gas, and digester gas. For the CHP usage, the manufacturers indicated whether or not the units were equipped for waste heat recovery. The amount of waste heat recovered by the customers at each site was generally not available to the manufacturers, so the survey did not request that data. For those units operating on natural gas, the survey asked the manufacturers to include the types of facilities where these units are located.

The results indicated that there are about 700 microturbines and fuel cells in California capable of producing more than 41 MW of electricity. Of the 700 units, four percent are fuel cells. Roughly half of the 700 units are certified models using natural gas. Of the remaining, there are more than 100 units operating on natural gas that were purchased before the DG Certification program became effective in 2003. The final 200 units operate on waste-gas fuels and are permitted by the local air districts.

About a quarter of all the units are equipped with CHP, and most of these units operate on natural gas. The use of CHP with natural gas applications is not surprising. To be economically competitive with grid power, DG units using natural gas should have a significant demand for the waste heat generated, such as heating water, running an absorption chiller, or providing space heating in buildings. Examples of locations of units fueled with natural gas using CHP are government facilities, schools, hotels, utilities, and libraries.

To put the currently ARB-certified DG equipment into perspective, California has a total of about 67,000 MW of total electricity production capabilities for the grid, with about 2,600 MW considered to be in the distributed generation size range, which is 20 MW or less in rated capacity. The units subject to this program represent 1.6 percent of the California DG market or 0.06 percent of the total electricity capable of being produced in the State for the grid.

C. PUBLIC HEALTH BENEFITS FROM CERTIFIED DG UNITS

Pursuant to SB 1298, the ARB DG Certification regulation requires DG technologies to meet stringent central station power plant emission standards by the earliest practicable date. Consequently, certified DG technologies are much cleaner than other, more traditional types of DG technologies, such as small turbines and reciprocating engines.

Calculating specific health benefits associated with the DG certification program is difficult, largely due to the low emissions and widespread deployment of the technologies. However, Table II-1 illustrates the more restrictive emission standards of the DG certification program compared to best available control technology (BACT) standards for small turbines, as permitted by local air districts.

Table II-1: Comparison of BACT Standards with Central Station Power Plant Standards (Lbs/MW-Hr)

Standard	NOx	CO	VOC
BACT for Small Turbines	0.5	6.0	1.0
Central Station Power Plant (required by SB 1298)	0.07	0.1	0.02
Reductions	86%	98%	98%

Since many DG applications are typically located in or near communities, it is certain that requiring these technologies to meet stringent emission standards protects the public health of California residents.

III. SUMMARY OF PROPOSED AMENDMENTS TO THE DG CERTIFICATION REGULATION

This chapter contains the purpose and conclusions of ARB's electrical generation technology review and a summary of the subsequent proposed amendments to the DG Certification regulation. A copy of the proposed amendments is located in Appendix A.

A. PURPOSE AND CONCLUSIONS OF TECHNOLOGY REVIEW

The current certification regulation required the ARB staff to conduct a technology review by July 2005 to evaluate if specific certification requirements should be modified. ARB staff committed to this review because at the time the regulation was adopted, the technologies that would be affected by the regulation had not yet entered or were just entering the California market. Very little information was available on these emerging technologies. Most of the units were still in the research and development stage and few were ready for commercialization.

The DG Certification regulation required that ARB's technology review address four specific areas of the regulation:

- the feasibility of 2007 standards;
- the credit given for utilizing combined heat and power (CHP) to meet these standards;
- the method for determining emissions durability; and
- the test methods and procedures used to certify a technology.

1. <u>Feasibility of 2007 Standards</u>

The current 2007 emission standards are based on central station power plant emission limits with an adjustment for distribution line loss. SB 1298 requires unpermitted DG technologies ultimately to meet these limits. At the time the regulation was adopted, fuel cells were expected to already be at these limits, but it was uncertain if microtubines could meet these limits by 2007. To date, ARB staff has certified six natural-gas-fueled DG units to the 2007 standards: five fuel cells, and one microturbine. Because these technologies have now been certified to the 2007 limits, staff believes these limits are feasible and is therefore not proposing any changes to the January 1, 2007, compliance date.

However, the ARB staff is proposing two minor changes to the 2007 standards: 1) specifying that these standards are applicable to fossil fuels (e.g., natural gas and liquefied petroleum gas (LPG)), and 2) eliminating the particulate matter (PM) emission standard. As will be discussed later, staff is proposing to bifurcate the DG Certification regulation into standards for fossil fuels and standards for waste-gas fuels. Staff is proposing that LPG be included with natural gas as a fossil fuel subject to the 2007 standards and that LPG be specified as meeting the standards of HD-5 propane.

The current 2007 PM emission standard is essentially the sulfur limit in Public Utility Commission (PUC) grade natural gas (one grain of sulfur per 100 standard cubic feet). Staff is proposing to eliminate this PM standard for natural gas because it is redundant: "natural gas" is defined in the regulation as PUC-quality gas. Staff proposes to not include a PM standard for LPG, as it is not expected to have any measurable amount of PM emissions.

2. Combined Heat and Power Benefit

The current regulation allows a manufacturer to use an energy credit to meet the 2007 standards if the unit is integrated and sold with combined heat and power (CHP) and the unit can achieve a minimum overall efficiency of 60 percent. The credit allows the recovered waste heat to be added to the total energy production of the DG unit at the rate of 1 MW-hr for each 3.4 million Btu's of recovered waste heat.

The credit given was based on limited information that was available at the time the regulation was developed. During the technology review, ARB staff spent an extensive amount of time searching for data related to the amount of waste heat utilized by facilities with certified equipment. As this is a manufacturer's certification program, facilities are not required to record the amount of waste heat recovered. This made it difficult for the ARB staff to assess if and how credit for CHP should be altered. The ARB staff concluded that there is no compelling data to alter the method or amount of credit given for CHP and is therefore not proposing any changes to the CHP credit. The staff is, however, proposing to clarify that CHP is based on electricity and useful heat from the unit (the heat that can actually be captured and used for other processes such as heating water and running an absorption chiller).

3. Emissions Durability

When the regulation was adopted, in-the-field source test data was not available for DG units to demonstrate the emissions durability of these emerging technologies. Staff included in the DG Certification regulation a requirement that certified units must meet the emission standards over a 15,000-hour operating period. Since newly certified DG technologies did not have 15,000 hours of operating time, this requirement became more of a technical discussion within the certification application.

There is still very little source test data on units in the field to indicate how well certified DG units are capable of maintaining compliance with the emission standards because there is no requirement for manufacturers to test the units sold to their customers. To require such testing would essentially undermine the concept of certifying equipment at the manufacturers' level, so the ARB staff considered other approaches to addressing durability. The ARB staff has determined that this can best be accomplished through a combination of additional data submittal, recordkeeping, and reporting requirements.

As proposed, a manufacturer would be required to identify the components of the DG unit that are most critical to ensuring compliance with the emission limits, such as fuel injectors, rotors, seals, and bearings for a microturbine, and fuel cell stacks and catalysts for fuel cells. In addition, the manufacturer will be required to keep records relating to how often these components are replaced and submit the records to the ARB staff at our request. In this manner, ARB staff will be able to track durability of equipment in the field and determine if a certification should be reviewed.

4. Test Methods and Procedures

Staff is proposing a number of modifications to the testing requirements and procedures section of the regulation.

a. Modify VOC Test Method

The regulation currently requires ARB Method 100 to be used to test NOx, CO, VOC, and oxygen. The VOC testing in Method 100 includes all volatile organic compounds. It was never ARB staff's intent to include methane and ethane in certification emission calculations. Consequently, staff is proposing to add a VOC method that would result in non-methane, non-ethane emission calculations and would provide more accuracy when measuring the low emission concentrations from technologies certified under this program. After discussing VOC test methods with ARB staff in the Monitoring and Laboratory Division, local air district staff, and the manufacturers' source-testing firms, ARB staff has determined that the best test method to use for the certification program is South Coast Air Quality Management District's source test method 25.3. A copy of test method 25.3 is included in Appendix C.

b. Eliminate Partial Load Testing

The current regulation requires testing at 50-percent, 75-percent, and 100-percent loads, with the certification emission rate calculated on a weighted emission rate basis. The three-load testing procedure was included in the regulation because at the time of adoption, there was concern that certified DG units—microturbines in particular—would be frequently operated at partial loads. During the technology review, ARB staff was able to evaluate usage data for certified DG units. The data indicated that most of these units are typically operated at full capacity and that these units are rarely used in a load-following mode. Consequently, the ARB staff is proposing to alter the testing procedure to require testing at only 100 percent load.

c. Eliminate Pre-Commercial Operation NOx Testing

Currently, manufacturers are required to test NOx emissions for each individual certified DG unit built for sale in California. The NOx emissions are to be tested using a portable testing device. During the implementation of the certification program, ARB staff determined that no portable devices exist that are capable of accurately measuring NOx emissions at the extremely low concentrations emitted by the devices certified pursuant to this program. In fact, measuring such low NOx emissions using state-of-the-art source test methods has proved to be challenging for manufacturers during the certification process. Therefore, the ARB staff is proposing to remove this ineffective NOx-testing requirement from the DG Certification regulation.

d. Other Changes to Testing Parameters

The ARB staff is proposing to add a method that manufacturers must use to calculate the amount of waste heat recovered from a unit's heat recovery system for purposes of calculating the CHP credit. Local air districts and industry representatives requested that ARB staff specify a method for calculating the amount of waste heat recovered to be used for this credit. The method proposed would utilize a water loop, wherein waste heat is transferred to a body of water which is allowed to cool before returning to absorb more energy, similar to a radiator in a car. The amount of waste heat recovered can be determined by the difference in temperature before and after the heat exchanger and the flow rate of the water.

Finally, staff is proposing to clarify that the generator output measured during the source test should be based on net power output, not the gross output of the unit. The generator output is used to calculate the lbs/MW-hr emission rate of the unit being certified. Measuring the net output will more accurately represent the actual available power from the unit.

B. OTHER PROPOSED MODIFICATIONS TO THE DG CERTIFICATION REGULATION

ARB staff considered other possible revisions to the DG Certification regulation not associated with the required technology review. The most significant of these proposed changes pertains to the inclusion of waste-gas applications of permit-exempt DG equipment. Other proposed revisions are intended to strengthen and clarify the regulation.

1. Addition of Waste Gas Emission Standards

Staff is proposing to add a certification protocol through which DG technologies that are using waste gas for fuel and are exempt from local air district permits can be certified through the ARB DG certification program. The current regulation, although allowing for fuels other than natural gas to be used for certification, does not contain a practical method in which to accomplish this. The composition of waste fuels varies from site to site and season to season. Therefore, local air districts have had to issue permits to otherwise permit-exempt equipment. The ARB staff proposes to bring these waste-gas applications into the DG certification program where they appropriately belong.

At the time the certification program was originally adopted, there was general consensus that waste-gas-fueled DG units would be subject to district permitting. During the technology review, ARB staff found that a number of microturbines and fuel cells sold in California were fueled by waste gases, but were exempt from local air district permits. Because SB 1298 requires every DG unit in California to be either permitted by the district or certified by the ARB, ARB staff asked the districts to issue permits for these applications until the regulation could be adjusted to accommodate waste-gas certifications.

The local air districts have been issuing permits to these applications but support integrating waste gas applications into the certification program. Manufacturers are also supportive of the ARB including waste-gas applications in the certification program, as this would be less costly and burdensome for their customers, who are obtaining individual project permits.

The ARB staff determined that to certify DG technologies on waste gas, this type of fuel would need to be defined in the regulation. As mentioned previously, the composition of waste gas varies from site to site and season to season. Staff determined that surrogate waste-gas fuels would be required.

The ARB staff collected speciation data on waste gases from digesters, landfills, and oil field sites. Staff evaluated the data, identified the major constituents of the waste-gas streams, and developed proposed surrogate gases for these three waste-gas applications (digesters, landfills, and oil-field waste gases). The surrogate waste-gas fuels are defined as follows:

- Digester gas – 60 to 65 percent methane and 35 to 40 percent carbon dioxide
- Landfill gas – 42 to 46 percent methane, 34 to 38 percent carbon dioxide, and 18 to 22 percent nitrogen
- Oil-field waste gas – 63 to 71 percent methane, 6 to 8 percent ethane, 9 to 11 percent propane, 7 to 9 percent carbon dioxide, and 7 to 9 percent carbon compounds with four or more carbon atoms per molecule

Manufacturers would be required to use these surrogate gases to certify for any of these waste-gas applications. They could certify to any or all of these fuels, depending on their business plans.

Staff is proposing two sets of waste gas standards, much like what is currently in the regulation. Staff is proposing 2008 interim waste-gas standards that are similar to the current 2003 limits. Unlike the 2003 standards, the waste-gas 2008 standards would not include a particulate matter (PM) standard nor would they include a separate, less stringent, set of limits for units integrated with CHP. A PM standard is not being proposed because the impurities in waste gas that would contribute to PM emissions will be removed prior to being used with DG units in the field. Staff is not proposing to include less stringent 2008 limits for units integrated with CHP because manufacturers would now only have to test at 100 percent power load, which should allow them to meet the more stringent limits.

The proposed 2013 waste-gas standards are identical to the current 2007 limits, except for the omission of a PM standard as described above. The 2013 standards reflect central station power plant emissions, as required in SB 1298. As with the 2007 standards, a manufacturer can use a CHP credit to meet the 2013 standards if the unit is integrated and sold with a heat recovery system and can achieve a minimum efficiency of 60 percent. The proposed waste-gas emission standards are presented in Table III-1 below.

Table III-1: Proposed Waste Gas Emission Standards

Pollutant	Emission Standard (lb/MW-hr)	
	On or after January 1, 2008	On or after January 1, 2013
NO_x	0.5	0.07
CO	6.0	0.10
VOCs	1.0	0.02

As mentioned earlier, the ARB staff is proposing to remove the particulate matter (PM) emission standard from the 2007 standards because we do not expect any significant PM emissions from gaseous fuels. Similarly, staff is not proposing a PM standard for waste-gas certification. Surrogate gases do not contain the impurities that are present in waste gas fuels, such as siloxanes and sulfur compounds, which would contribute to PM emissions. Waste-gas fuels in the field will require treatment to remove these impurities prior to being used in microturbines or fuel cells.

Manufacturers of DG technologies that are integrated with CHP will be able to calculate an energy credit for the useful waste heat recovered to meet the 2013 emission standards, the same credit that is allowed for meeting the current 2007 standards. The credit allows the recovered waste heat to be added to the total energy production of the DG unit at the rate of 1 MW-hr for each 3.4 million Btu's of recovered waste heat. To encourage the use of high efficiency CHP, the credit can only be taken when the DG technology is integrated with the CHP package and the unit can achieve a minimum efficiency of 60 percent.

Based on manufacturers' source test data and source test data from users of microturbines and fuel cells fueled by waste gases, ARB staff believes that both fuel cells and microturbines can currently meet the 2008 standards. A summary of the source test data ARB staff collected for waste gas applications is included in Appendix D. Staff believes that the January 1, 2008, compliance date will provide the manufactures with enough lead time to obtain certification for their waste gas units.

ARB staff believes that fuel cells can currently meet the 2013 standards, but that microturbines will need more time to achieve these standards on waste gas. The January 1, 2013, compliance date will give manufacturers five years to research and develop new products to meet central station emission limits with waste gas. Much of the research and development effort needed to meet the 2013 standards will have already been spent on achieving the 2007 natural gas standards.

2. Fees

ARB staff is proposing to increase fees to fully cover costs to the State to implement this program, as allowed by SB 1298. Initial certification application fees under the proposed amendments would increase from $2,500 to $7,500. Staff had estimated $2,500 per application when the DG certification program was being developed in 2001, but subsequent experience with the program has shown the original fee estimate to be inadequate to recover the cost of implementing the DG certification program. The new fee is based on an estimate of about 60 hours of the ARB staff time to review the certification applications.

Manufacturers of technologies that can meet the 2013 standards by January 1, 2008 (such as fuel cells), will be exempt from submitting an initial fee. ARB staff is proposing no initial application fee for these technologies to provide an economic incentive for early introduction of the cleanest waste-gas-fueled DG technologies.

ARB staff is proposing a fee to cover the costs incurred by ARB for staff time required to process voluntary applications. Currently, applicants seeking voluntary certification would not be charged any application fee. Manufacturers of technologies that are seeking voluntary certification (those technologies that do not emit an air contaminant) would be required to submit a fee of $2,500. Staff estimates that it would take about 20 hours to process applications that do not contain source test results. To date, ARB has not received any applications for voluntary certifications.

The current fee assessment for recertification is $2,500. The ARB staff proposes to maintain that fee for DG units that do not require a source test for recertification. Staff proposes to assess a fee of $7,500 for DG units that require a source test for recertification. This fee is based on staff time estimates of about

20 hours for applications that do not contain source test results, and about 60 hours to process applications that do contain source test results.

3. Applicability

ARB staff is proposing to expand the allowable exemptions to the regulation to include units operated by the manufacturer for quality assurance testing, and units that are part of a research operation which the Executive Officer has approved.

Staff is also proposing to clarify that all portable electrical generation technologies are exempt from this program, not just those that are registered in ARB's Portable Equipment Registration Program. Portable DG technologies have not been certified under this program, nor is it ARB's intent to subject them to the certification regulation. These small portable DG units are already regulated under other ARB and United States Environmental Protection Agency (U.S. EPA) programs. Small natural gas (or spark-ignition engine) units are regulated under ARB's Small Off-Road Engine (SORE) program. Small diesel engines are subject to U.S. EPA standards.

4. Recertification

Since the waste-gas emission standards are five years apart (2008 and 2013) ARB staff is proposing that certifications issued to units meeting the 2008 standards on waste gas be valid for five years or to January 1, 2013, whichever comes first. For consistency, staff is proposing to expand the duration of certifications based on the 2007 fossil fuel standards from four years to five years as well.

Staff is proposing that when currently certified DG units are recertified, they will be subject to the proposed new requirements. This may include submitting more information in their recertification application regarding emissions durability design and the unit's critical components. This will ensure that certified units continue to meet clean technology standards.

5. Other Proposed Changes

ARB staff is proposing to modify the inspection and enforcement provisions in the regulation, modify and add terms in the definitions section, and make other editorial changes throughout the regulation. These changes are considered to be non-substantive and are intended to improve and clarify the DG Certification regulation.

C. ALTERNATIVES CONSIDERED

The current DG Certification regulation required a technology review for consideration of revisions to the regulation. After conducting the technology review, staff believed that there were revisions that could make the regulation clearer and more effective. Nevertheless, there remained the option of taking no action to amend the existing regulation. The regulation has been in effect for five years with a number of units being certified. ARB staff was able to address testing and reporting issues that arose during this time without regulatory changes. However, it is ARB's responsibility to ensure unpermitted waste-gas technologies conform to the intent of SB 1298 and be added to the certification program as soon as possible. Therefore, the ARB staff determined that is was essential to amend the certification regulation now to include the waste gas applications. Once staff decided to revise the DG Certification regulation, we assessed the need for other improvements and clarifications to the regulation and proposed additional revisions.

IV. ENVIRONMENTAL IMPACTS OF PROPOSED AMENDMENTS

The ARB staff has conducted an analysis of the potential environmental impacts of the proposed amendments to the DG Certification regulation. Based on our analysis, we have determined that the proposed amendments would have no significant adverse environmental impacts.

A. LEGAL REQUIREMENTS APPLICABLE TO THE ENVIRONMENTAL IMPACT ANALYSIS

The California Environmental Quality Act (CEQA) and the ARB policy require an analysis to determine the potential environmental impacts of proposed regulations. The Secretary of Resources, pursuant to Public Resources Code section 21080.5, has certified the ARB rulemaking process. Consequently, the CEQA environmental analysis requirements may be included in the Initial Statement of Reasons (ISOR) for this rulemaking. The ISOR serves as a functionally equivalent document of an initial study, a Negative Declaration, and an Environmental Impact Report. In addition, staff will respond, in the Final Statement of Reasons for the amendments to the regulation, to all significant environmental issues raised by the public during the public review period or at the Board public hearing.

Public Resources Code section 21159 requires that the environmental impact analysis conducted by the ARB include the following:

- An analysis of the reasonably foreseeable environmental impacts of the methods of compliance
- An analysis of reasonably foreseeable feasible mitigation measures
- An analysis of reasonably foreseeable alternative means of compliance with the amendments to the DG Certification regulation

Regarding mitigation measures, CEQA requires an agency to identify and adopt feasible mitigation measures that would minimize any significant adverse environmental impacts described in the environmental analysis.

B. AIR QUALITY IMPACTS OF THE PROPOSED AMENDMENTS

The proposed amendments to the DG Certification regulation will reduce emissions of NOx, CO, and VOCs from DG technologies exempt from local air district permits and used in waste-gas applications. Currently, these technologies have to obtain permits from the local air districts. Inclusion of these waste-gas applications into the DG certification program will subject the technologies to more stringent emission standards than is typically required by the local air districts for similar DG units—such as small turbines and reciprocating engines—especially when considering that these technologies must meet central power plant emission levels by 2013. (See Table II-1 on page 6 for illustrative example.)

C. REASONABLY FORESEEABLE ENVIRONMENTAL IMPACTS OF THE METHODS OF COMPLIANCE

The ARB staff has not identified any significant adverse environmental impacts from complying with the amendments to the DG Certification regulation.

D. REASONABLY FORESEEABLE MITIGATION MEASURES

CEQA requires an agency to identify and adopt feasible mitigation measures that would minimize any significant adverse environmental impacts described in the environmental analysis. ARB staff has concluded that no significant adverse environmental impact would occur from adoption of, and compliance with, the proposed amendments to the DG Certification regulation. Therefore, no mitigation measures would be necessary.

E. REASONABLY FORESEEABLE ALTERNATIVE MEANS OF COMPLIANCE WITH THE PROPOSED AMENDMENTS

The ARB is required to do an analysis of reasonably foreseeable alternative means of compliance with the proposed amendments to the DG Certification regulation. The ARB staff concluded that the proposed amendments provide the greatest degree of flexibility and the least burdensome approach to reducing public exposure to emissions from new DG technologies and complying with SB 1298.

F. ENVIRONMENTAL JUSTICE

ARB is committed to evaluating community impacts of proposed regulations including environmental justice concerns. Because some communities experience higher exposure to air pollutants, it is a priority of ARB to ensure that full protection is afforded to all Californians. The proposed amendments to the DG Certification regulation are not expected to result in significant negative impacts in any community. The proposed amendments to the DG Certification regulation would likely result in decreased emissions of NOx, VOC, and CO. These reductions would occur by adding waste-gas-fueled technologies to the certification program. The proposed amendments would reduce the exposure to pollutants to residents and off-site workers near the operation of certified DG units fueled by waste gases.

V. ECONOMIC IMPACTS OF PROPOSED AMENDMENTS

This chapter discusses the economic impacts that the proposed amendments to the DG Certification regulation may have on businesses.

Some of the amendments staff is proposing to the DG Certification regulation are expected to have a positive economic impact on affected manufacturers. Source-testing efforts will be reduced by requiring testing at only 100-percent load instead of the current requirement of testing at three power-production loads. In addition, each certified DG unit will no longer require a test for NOx emissions using a NOx analyzer prior to commercial operation. And finally, the DG certification duration will be extended from four years to five years, furthering the positive economic impact for manufacturers.

The ARB staff does not expect complying with the proposed waste-gas standards to cause adverse economic impacts on businesses. ARB staff believes that both fuel cells and microturbines operating on waste gases can currently meet the proposed 2008 standards. Manufacturers should not incur significant adverse economic impacts from complying with the proposed 2013 waste-gas emission standards, as these standards are similar to the 2007 standards with which manufacturers must currently comply for their natural-gas-fueled units. ARB staff believes that fuel cells can currently meet the 2013 standards, but that microturbines will need more time to achieve these standards on waste gases. The January 1, 2013, compliance date will give manufacturers five years to research and develop new products to meet central station emission limits with waste gases. Much of the research and development effort needed to meet the 2013 standards will have already been spent on achieving the 2007 natural gas standard.

The overall statewide cost of the proposed amendments is estimated to be $1,800,000, with an estimated individual business cost of $ 135,000 to $158,000 for each DG model certified (assuming each unit is certified to operate on three waste gas fuels). Businesses will incur costs for conducting an emissions source test on each DG model and fuel type to be certified, preparing and submitting a certification application, and paying an application fee.

The proposed amendments to the DG Certification regulation are not expected to cause a noticeable change in California employment or business status.

A. LEGAL REQUIREMENT

Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment shall include a consideration of the impact of the proposed regulation on California jobs, business expansion, elimination, or creation, and the ability of California businesses to compete.

Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies and the cost or savings in federal funding to the State.

Health and Safety Code section 57005 requires the ARB staff to perform an economic impact analysis of submitted alternatives to a proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. The proposed revisions to the certification program do not constitute a major regulation.

B. SUMMARY OF THE ECONOMIC IMPACTS

The businesses that may be affected by the amendments to the DG Certification regulation fall primarily into two Standard Industrial Classifications (SICs)/new North American Industry Classifications (NAICs). A list of the industries that the ARB staff has been able to identify is provided in Table V-1.

Table V-1: Potential Industries Affected by the Proposed Amendments to the DG Certification regulation

SIC/NAIC	Industry
3511/333611	Turbine and turbine generator set units manufacturing
3629/335999	Fuel cells, electrochemical generators manufacturing

The ARB staff has identified six manufacturers that will potentially be impacted by the proposed amendments: the same manufacturers who have already certified their units on natural gas. Only one of these companies is in California. Two of these companies are small businesses and neither company is in California. Table V-2 summarizes potentially affected manufactures by technology type and location.

Table V-2: DG Manufacturers by Technology Type and Location

DG Technology	Non-California Company	California Company	Total
Microturbines	2	1	3
Fuel Cells	3	0	3
Total	5	1	6

C. COST IMPACTS TO BUSINESSES

Costs to affected businesses for complying with the proposed waste gas emission standards can be divided into three major areas: the cost of an application fee, the cost for preparing a certification application package, and the cost to perform emissions source testing. The three major areas are listed below:

1. Application Fees

The proposed amendments would change the fee structure of the program to fully cover costs to the State to implement this program. The application fee for initial certification of a natural-gas-fueled unit is proposed to increase $5,000, from $2,500 to $7,500. Under the proposed amendments, initial certifications of units operating on waste gas will require an application fee of $7,500 per fuel. This fee is based on an estimate of 60 hours of the ARB staff time to review the certification applications. Manufacturers of technologies that can meet the proposed 2013 standards by 2008 (such as fuel cells) will be exempt from submitting an initial fee.

Manufacturers of technologies that are seeking voluntary certification (those technologies that do not emit an air contaminant) would be required to submit a fee of $2,500 per fuel, although, to date, ARB has not received any applications for voluntary certifications.

DG units that do not require a source test for recertification will be assessed a fee of $2,500 per fuel. Recertification of a DG unit that requires a source test will be assessed a fee of $7,500 per fuel.

2. Application Preparation Costs

ARB staff assumed that the estimated cost to the manufacturer to prepare a certification application package that contains all of the required information and supporting data is approximately $15,000. This cost is based on an estimate of 120 hours of the manufacturer's time to prepare the application and to arrange and oversee the source testing required for the application.

3. Source Testing Costs

Manufacturers will be required to provide a source test report in their certification application to demonstrate compliance with the proposed waste gas emission standards. The ARB staff has identified three types of waste gases that can be used to fuel a DG unit: digester, landfill, and oil-field waste gas. A manufacturer must source test a DG unit on each type of waste gas that will be used for operating the unit in California. Each certification will be specific to the type of waste gas tested. Consequently, a DG unit could require up to six separate sources tests: one for each of the three waste gases to meet both the 2008 and 2013 emission standards.

The estimated cost for performing the source tests and analyzing the results is $10,000. The source-test cost estimate is based on discussions with manufacturers and private source-testing companies. The estimated cost for supplying enough waste gas to perform a source test is $20,000. The waste gas cost estimate is based on surveying manufacturers and representatives from the Advanced Power and Energy Program at University of California, Irvine.

4. Summary of Compliance Costs

Based upon the number of microturbines currently certified, ARB staff anticipates two companies will certify one unit each and one company will certify two units to the 2008 waste-gas emission standards. Staff expects that these four units will also be certified at a later date to the 2013 waste-gas emission standards. Similarly, based upon the number of fuel cells currently certified, ARB staff anticipates two companies will certify one unit each and one company will certify two units to the 2013 standards.

Each cost per fuel includes a $15,000 application preparation cost, a $10,000 source test cost, $20,000 for fuel to supply the source test, and either a $7,500 application fee for microturbines or no application fee for fuel cells due to early compliance with the 2013 standards. Therefore, the total cost per waste-gas certification should range from $45,000 for fuel cells to $52,500 for microturbines.

The overall statewide cost for complying with the 2008 waste gas standards is estimated to be $630,000, which is based on four microturbines being certified for all three waste-gas fuels (4 x 3 x $52,500). This cost is only applicable to microturbine manufacturers, as the ARB staff expects the fuel cells to be already capable of meeting the 2013 emission standards.

The overall statewide cost for complying with the 2013 waste-gas standards is estimated to be $1,170,000, which includes $630,000 from the microturbine manufacturers, as described above, and $540,000 from the fuel cell manufacturers (4 x 3 x $45,000). Fuel cells are expected to incur less cost for certifying to the 2013 standards than microtubines because the proposed amendments allow for an application fee exemption for technologies that demonstrate early compliance with the 2013 standards.

Table V-3 presents the cost per technology type to comply with the standards:

Table V-3: Cost per Technology Type for Complying with Proposed DG Certification Amendments

DG Technology	Cost ($) per Fuel	Possible Waste Gas Fuels Tested	Number of 2008 Certifications	Number of 2013 Certifications	Total ($)
Microturbine	52,500	3	4	4	1,260,000
Fuel Cell	45,000	3	0	4	540,000
Total Cost					1,800,000

To minimize the economic impact to manufacturers for complying with the 2013 standards, the ARB staff included provisions in the certification requirements for an energy credit for highly efficient combined heat and power packages that are integrated with DG technologies, similar to the current 2007 standards. Manufacturers may choose to sell their units in 2013 with integrated CHP to reduce any possible redesign costs. As was mentioned earlier in this chapter, much of the research and development effort needed to meet the 2013 waste-gas standards will have already been spent on achieving the 2007 standards for natural gas, as these standards are numerically identical. Therefore, manufacturers should incur similar costs for complying with the 2013 standards as they do for complying with the 2008 standards.

Although manufacturers will incur some costs up front for certifying to the waste-gas standards, having certified units may assist manufacturers with marketing their products in California. Customers would benefit from purchasing certified DG units because it eliminates the need for multiple, site-specific district permits and source testing, as is the case now.

D. POTENTIAL IMPACT ON BUSINESS COMPETITIVENESS

The proposed amendments are not expected to adversely impact California business competitiveness because all affected manufacturers that make products for sale into California will be required to meet the same emission standards requirements. Of the six DG manufacturers that have certified technologies for distribution in California, only one is located in California.

E. POTENTIAL IMPACT ON EMPLOYMENT, BUSINESS CREATION, ELIMINATION, OR EXPANSION

The proposed amendments are not expected to cause a noticeable change in California employment and business status. Based upon the current DG Certification program, all six companies are expected to experience economic impacts by the proposed amendments. These impacts should be offset by the positive impacts of the proposed amendments on all manufacturers. These positive impacts will allow DG units to penetrate the California market and, in turn, allow for manufacturers to initiate production expansion.

F. POTENTIAL IMPACT ON SMALL BUSINESSES

The ARB staff has identified two out of six manufacturers as small businesses that will potentially be impacted by the proposed amendments. Both small businesses manufacture fuel cell technologies; however, neither company is in California. These businesses should incur costs of $135,000 for each DG unit certified to comply with the proposed 2013 waste-gas standards.

G. POTENTIAL IMPACT ON PUBLIC AGENCIES

The proposed amendments should have no significant fiscal impact on state or local agencies. It is anticipated that the ARB will incur costs starting in 2007 to certify distributed generation technologies to the waste gas emission standards. The proposed increase in certification fees from $2,500 to $7,500 coupled with existing budgets and resources should offset these costs.

The ARB staff will also be responsible for enforcing the requirements in the DG certification program including ensuring that DG units are meeting their certified limits in the field. Existing ARB staff should be able to accommodate the need to perform inspections of the certified units, thus allowing for additional costs to be absorbed within existing budgets.

VI. REFERENCES

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Appendix A

Proposed Regulation Order

Amendments to the Distributed Generation Certification Regulation

PROPOSED AMENDMENTS TO THE DISTRIBUTED GENERATION CERTIFICATION REGULATION

Amend sections 94200-94214, in article 3, subchapter 8, chapter 1, division 3 of title 17, California Code of Regulations, to read as follows:

Article 3. **Distributed Generation Certification Program**

94200. **Purpose.**

These regulations implement the program mandated by Health and Safety Code section 41514.9 for certification of electrical generation technologies. After January 1, 2003, it will be unlawful to either:

(a) manufacture any DG Unit for sale, lease, use, or operation in the State of California, or

(b) sell or lease, or offer for sale or lease, any DG Unit for use or operation in the State of California

unless the DG Unit is certified by the Air Resources Board pursuant to these regulations or is otherwise exempt from certification as hereinafter provided.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94201. **Applicability**

Any DG Unit manufactured after January 1, 2003, for sale, lease, use, or operation in the State of California; or any new DG Unit sold or leased, or offered for sale or lease, for use or operation in the State of California after January 1, 2003, shall be certified by the Air Resources Board unless the DG Unit:

(a) does not emit an air contaminant when operated,

(b) is ~~registered under the Portable Engine and Equipment Registration Program (title 13, California Code of Regulations commencing at section 2450)~~portable,

(c) is used only when electrical or natural gas service fails or for emergency pumping of water for fire protection or flood relief, or

(d) is not exempt from an air pollution control district or air quality management district's permitting requirements,

(e) is part of a research operation that has been approved in writing by the Executive Officer prior to commencement of operations, or

(f) is operated by the manufacturer at the manufacturing facility prior to sale or lease for the purpose of quality-assurance testing.

94201.1

Any DG Unit that was purchased or leased while the DG Unit was certified can continue to be operated by the owner or lessee after the certification has expired so long as the DG Unit meets the standard to which it was certified.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94202. **Definitions**

For the purposes of these regulations, the following definitions apply:

(a) **Air Contaminant**. Shall have the same meaning as set forth in section 39013 of the Health and Safety Code.

(b) **Air Pollution Control Equipment**. Equipment that eliminates, reduces, or controls the issuance of air emissions.

(c) **Applicant.** A manufacturer or manufacturer's designated agent applying for certification of a DG Unit.

(d) **ARB**. The California Air Resources Board.

(e) **Btu**. British thermal unit.

(f) **CO.** Carbon monoxide.

~~(e)~~ (g) **Combined Heat and Power (CHP)**. A ~~DG Unit~~system that ~~produces both electric power~~ recovers thermal energy and ~~process~~converts it into useful heat from electrical power generation equipment.

(h) **Digester Gas.** Gases produced from the decomposition of sewage.

~~(f)~~ (i) **Distributed Generation (DG)~~Unit~~**. Electrical generation technologies that produce electricity near the place of use.

(j) **DG Unit.** A piece of distributed generation equipment.

~~(g)~~ (k) **District.** Shall have the same meaning as set forth in part 3, commencing with section 40000 of the California Health and Safety Code.

~~(h)~~ (l) **Electrical Generation Technology**. Reciprocating engines, external combustion engines, combustion turbines, photovoltaics, wind turbines, fuel cells, or any combination thereof.

(m) **Energy Efficiency**. The amount of useful heat and electricity produced by a DG Unit divided by the higher heating value of the fuel used to produce the useful heat and electricity, expressed as a percentage.

~~(i)~~ (n) **Executive Officer**. The Executive Officer of the California Air Resources Board or his or her designee.

~~(j)~~ (o) **Executive Order**. An order issued by the Executive Officer of the Air Resources Board certifying compliance of a DG Unit with the applicable requirements of this article.

(p) **Fossil Fuels.** Fuels such as coal, oil, and natural gas; so-called because they are the remains of ancient plant and animal life.

(q) **Higher Heating Value.** The amount of heat released by the combustion of material at 25 °C once the products of combustion have returned to a temperature of 25 °C.

(r) **Landfill Gas.** Gases produced from the decomposition and volatilization of materials in landfills

(s) **LPG.** Liquid petroleum gas.

(t) **MW-hr.** Megawatt-hour.

(u) **Natural Gas.** California Public Utility Commission (CPUC) quality natural gas.

(v) **NOx.** Oxides of nitrogen, expressed as NO_2.

(w) **Oil-Field Waste Gas.** Gases produced from the drilling of oil wells and pumping of oil from wells that are not eligible for delivery to the utility pipeline system.

(x) **Portable.** Shall have the same meaning as set forth in title 13 section 2452(z) of the California Code of Regulations.

(y) **Research Operation.** Investigation, experimentation, or research to advance the knowledge of distributed generation technologies.

(z) **Useful Heat.** The heat that can be captured and used for other processes such as heating water or running an absorption chiller.

(aa) **VOC.** Volatile organic compounds, expressed as hexane.

~~(k)~~ (bb)**Zero Emission Technology**. Any technology that does not emit an air contaminant as defined in section 94202(a).

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94203. **Requirements.**

(a) On or after January 1, 2003, any DG Unit subject to this regulation must be certified pursuant to section 94204 to one of the following sets of emission standards in Table 1.

(1) DG Unit not integrated with combined heat and power,
(2) DG Unit integrated with combined heat and power technology.

Table 1.
January 1, 2003 Emission Standards (lb/MW-hr)

Pollutant	DG Unit not Integrated with Combined Heat and Power (a)(1)	DG Unit Integrated With Combined Heat and Power (a)(2)
Oxides of Nitrogen (NO_x)	0.5	0.7
Carbon Monoxide (CO)	6.0	6.0
Volatile Organic Compounds (VOCs)	1.0	1.0
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf

(A) DG Units that use combined heat and power may be certified to the emission standard in section (a)(2) above if the DG Units are sold with combined heat and power technology integrated into a standardized package by the

Applicant and the DG Units achieve a minimum energy efficiency of 60 percent ~~(useful energy out/fuel in)~~. The efficiency determination shall be based on 100 percent load.

(B) DG Units that are sold with a zero emission technology integrated into a standardized package by the Applicant may have the electrical power output of the zero emission technology added to the electrical power output of the DG ~~unit~~ Unit to meet the emission standards in (a)(1) and (a)(2) above.

(b) On or after January 1, 2007, any DG Unit subject to this regulation fueled by a fossil fuel must be certified pursuant to section 94204 to the following set of emission standards in Table 2.

Table 2.
~~January 1,~~ 2007 Fossil Fuel Emission Standards ~~(lb/MW-hr)~~

Pollutant	Emission Standard (lb/MW-hr)
~~Oxides of Nitrogen (NO_x)~~	0.07
~~Carbon Monoxide (CO)~~	0.10
~~Volatile Organic Compounds (VOCs)~~	0.02
~~Particulate Matter (PM)~~	~~An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf~~

DG Units that ~~use~~produce combined heat and power may take a credit to meet the emission standard above. Credit shall be at the rate of one ~~megawatt-hour (~~MW-hr~~)~~ for each 3.4 million ~~British Thermal Units (BTU's)~~Btu's of heat recovered. To take the credit, the following must apply:

(1) DG Units are sold with combined heat and power technology integrated into a standardized package by the Applicant; and

(2) DG Units achieve a minimum energy efficiency of 60 percent. ~~(useful energy out/fuel in) in the conversion of the energy in the fossil fuel to electricity and process heat. The efficiency determination shall be based on 100 percent load.~~

(c) Any DG Unit subject to this regulation and fueled by digester gas, landfill gas, or oil-field waste gas must be certified pursuant to section 94204 to the emission standards in Table 3.

Table 3.
Waste Gas Emission Standards

Pollutant	**Emission Standard (lb/MW-hr)**	
	On or after January 1, 2008	**On or after January 1, 2013**
NO_x	0.5	0.07
CO	6.0	0.10
VOC	1.0	0.02

DG Units that produce combined heat and power may take a credit to meet the January 1, 2013, emission standard above. Credit shall be at the rate of one MW-hr for each 3.4 million Btu's of heat recovered. To take the credit, the following must apply:

(1) DG Units are sold with combined heat and power technology integrated into a standardized package by the Applicant; and

(2) DG Units achieve a minimum energy efficiency of 60 percent.

~~(c)~~ (d) DG Units must meet applicable emission standards for 15,000 hours of operation when operated and maintained according to the manufacturer's instructions.

~~(d)~~ (e) By July 2005, the ARB staff must complete an electrical generation technology review to evaluate if the requirements in (b) and (~~c~~d) above and section 94207 should be modified and report its findings to the Board.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94204. **Certification Procedure.**

(a) Each application for certification and the fee, as specified in section 94210, shall be submitted in a format approved by the Executive Officer and include, at a minimum, the following information:

(1) name of the Applicant, a contact person, mailing address (street and electronic), and telephone number;

(2) a description of the DG Unit and model number;

(3) maximum output rating (kilowatt);

(4) fuel type and analysis for which certification is being sought;

(5) type or description of any emission control equipment used;

(6) listing of components of the DG Unit most critical to ensuring continued compliance with the emission limits (such as fuel injectors, rotors, seals and bearings for a microturbine and fuel cell stacks and catalysts for fuel cells); and,

~~(6)~~ (7) emissions test data, supporting calculations, quality control/assurance information, and all other information needed to demonstrate compliance with the requirements in sections 94203 (a) through (~~c~~d).

(b) Within 30 calendar days of receipt of an application, the Executive Officer shall inform the Applicant in writing if the application is complete or deficient. If deemed deficient, the Executive Officer shall identify the specific information required to make the application complete.

(c) Within 60 calendar days of the application being deemed complete, the Executive Officer shall issue or deny certification.

(d) Upon finding that a DG Unit meets the requirements of this article, the Executive Officer shall issue an Executive Order of Certification for the DG Unit. The Executive Officer shall provide a copy of the Executive Order of Certification to the Applicant.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94205. **Voluntary Certification.**

DG Units that do not emit air contaminants while operating may submit information requested in section 94204 (a)(1) through (3), and any information necessary to demonstrate that there are no emissions of air contaminants, to the Executive Officer for voluntary certification.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94206. **Labeling Requirements.**

(a) The Applicant shall affix a certification label on a visible location on each certified DG Unit.

(b) The certification label must be of durable material and be permanently attached to the DG Unit.

(c) The certification label must contain the year of the conforming emission standards, the fuel type used, and the number of the Executive Order of Certification.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94207. **Testing.**

(a) Sampling methodology used must conform to ARB testing procedures. Alternate or modified test methods ~~must~~may be ~~submitted for approval~~used if approved in writing by the Executive Officer prior to use for certification.

~~(1)~~ Testing shall be conducted in accordance with the following methods~~, which are incorporated by reference herein~~:

NO_x, CO, ~~VOC~~ and Oxygen:	ARB Test Method 100 (as adopted on July 28, 1997)
VOC:	South Coast AQMD Method 25.3 (as published in March 2000)
Gas Velocity and Flow Rate:	ARB Test Methods 1, 2, 3, and 4 (as adopted on July 1, 1999)

(b) ~~California Public Utility Commission (CPUC) quality~~Only natural gas, LPG, digester gas, landfill gas, or oil-field waste gas, as defined in section 94202, meeting the requirements of section 94207 (d)(7) shall be used for certification testing. Other fuels may be used upon the written approval ~~by~~of the Executive Officer.

(c) The DG Unit shall be configured as it will be marketed, including any ~~Any~~ additional control equipment or other devices that affect emissions ~~shall be applied to the DG Unit and operated as marketed for the testing period~~.

(d) Testing parameters.

(1) A minimum of three valid test runs must be conducted. ~~Each test is~~Tests are to be run consecutively. Justification for invalid test runs or time gaps between runs must be included in the test report.

(2) Testing commences after the DG Unit has reached stable operation.

(3) Each run must be conducted ~~for three power production loads: 50 percent of generator gross output, 75 percent of generator gross output, and~~ at 100 percent of generator ~~gross~~ net output.

(A) A load bank may be used to establish the load.

(B) The DG Unit must be operated for a sufficient period of time to demonstrate stability in the emission readings at constant load and to ensure the collection of representative and quantifiable samples.

(4) Generator output (MW-hr), based on ~~gross~~net output, shall be measured during each valid test run. A calibrated electric meter shall be used for the measurements. The meter shall ~~be calibrated according to~~ meet the American National Standards Institute's Code for Electricity Metering (ANSI C12.1-as of July 9, 2001).

(5) Recovered heat shall be measured using a water loop device, measuring the water flow rate, inlet temperature, and outlet temperature.

~~(5)~~ (6) The emission rate shall be expressed in lb/MW-hr ~~and shall be calculated according to the following formula and weighting factors:~~.

~~(A) The results from the three valid test runs at 50 percent load shall be arithmetically averaged and multiplied by 0.2;~~

~~(B) The results from the three valid test runs at 75 percent load shall be arithmetically averaged and multiplied by 0.5; and~~

~~(C) The results from the three valid test runs at 100 percent load shall be arithmetically averaged and multiplied by 0.3.~~

~~The results for (A), (B) and (C), above, shall be added together to calculate the certification emission rate.~~

~~(6) Prior to commercial operation, each DG Unit shall be tested for NOx emissions at 100 percent load using a NOx analyzer that has been calibrated according to EPA CTM-022 (dated May, 1995) and approved by the Executive Officer. DG Units meeting the requirements of section 94203 (b) on or before January 1, 2003 will be exempt from this requirement.~~

~~(7) Alternate testing parameters may be used upon approval by the Executive Officer.~~

(7) Certification Fuels

(A) Natural gas.

(B) LPG that meets the standards of HD-5 propane.

(C) Surrogate digester gas that is composed of 60 to 65 percent methane and 35 to 40 percent CO_2, by volume.

(D) Surrogate landfill gas that is composed of 42 to 46 percent methane, 34 to 38 percent CO_2, and 18 to 22 percent N_2, by volume.

(E) Surrogate oil-field waste gas that is composed of 63 to 71 percent methane, 6 to 8 percent ethane, 9 to 11 percent propane, 7 to 9 percent CO2, and 7 to 8 percent carbon compounds with four or more carbon atoms per molecule, by volume.

(e) Alternative testing procedures may be used upon written approval of the Executive Officer, if alternative procedures are deemed to be equivalent or more accurate than the prescribed procedures.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94208. **Recordkeeping.**

(a) The Applicant must retain all information used for the certification application.

(b) Upon request of the Executive Officer, the Applicant will submit information to the ARB on the number and location of certified DG Units ~~that have been sold~~ in California.

(c) ~~Upon request of the Executive Officer, the Applicant will submit to the ARB the serial numbers, emissions durability information, and information gathered from measurements made pursuant to section 94207(d)(6) of certified DG Units sold in California~~The Applicant shall maintain a log identifying the components listed pursuant to section 94204 (a)(6) that are replaced, the date of replacement and the hours of operation each replaced component was used.

(d) All records maintained pursuant to this certification program must be retained for a period of five years after the certification has expired.

(e) All records maintained pursuant to this certification program shall be submitted to the ARB upon request of the Executive Officer.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94209. **Recertification.**

(a) Certification is valid for ~~four~~five years, except ~~where the test results for the initial certification of the DG unit does not meet the requirements~~ as specified in section ~~94203~~ (b)~~. The certification for these DG units shall be valid until January 1, 2007.~~ below.

(b) Digester gas, landfill gas, and oil-field waste gas fueled DG Units certified pursuant to the January 1, 2008, emission standards of section 94203 (c) shall be valid for five years, but no later than January 1, 2013.

(c) To recertify, the applicant must submit information required in section 94204 (a) (1) through (6), detail any changes to the design or operation of the DG Unit, and provide information to satisfy any new certification requirements since the time of initial certification or recertification.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94210. **Fees.**

(a) Fees shall be due and payable to the Executive Officer at the time an application is filed.

(b) DG Units ~~subject to these regulations~~ will be assessed a fee of $~~2500.~~7,500 for ~~certification and/or~~ recertification.

(c) DG Units seeking voluntary certification through section 94205 will be ~~exempt from fees for~~ assessed a fee of $2,500 for certification and/or recertification.

(d) DG Units meeting the January 1, 2013, requirements of section 94203(~~b)~~c) on or before January 1, ~~2003~~2008, will be exempt from certification fees ~~for certifying to the requirements in section 94203(a).~~ . These units will be subject to fees upon recertification.

(e) DG Units applying for recertification will be assessed a fee of either $7,500 if a new source test is required as part of the application package, or $2,500 if a new source test is not required.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94211. **Inspection.**

The Executive Officer, or an authorized representative of the Executive Officer, may periodically inspect manufacturers of DG Units for sale, lease, use or operation in California ~~or,~~; distributors~~,~~ and retailers selling or leasing DG Units for use or operation in ~~the state of~~ California; and, operators of DG Units in California. The Executive Officer, or an authorized representative, may conduct ~~such~~any tests ~~as are~~ deemed necessary to ensure compliance with these regulations. Failure of a manufacturer, distributor, ~~or~~ retailer, or operator to allow access for inspection purposes shall be grounds for suspension or revocation of certification.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94212. **Denial, Suspension or Revocation of Certification.**

(a) The Executive Officer for just cause may deny, suspend or revoke an Executive Order of Certification in any of the following circumstances:

(1) the Applicant has materially misrepresented the meaning, findings, effect or any other material aspect of the certification application, including submitting false or incomplete information in its application for certification regardless of the Applicant's personal knowledge of the falsity or incompleteness of the information;

(2) the test data submitted by the Applicant to show compliance with this regulation have been found to be inaccurate or invalid; or,

(3) the certified unit has failed in-use to comply with the findings set forth in the Executive Order. For the purposes of this section, noncompliance with the certification may include, but is not limited to:

(A) a repeated failure to perform to the standards set forth in this article;

(B) modification by the manufacturer of the DG Unit that results in an increase in emissions or changes the efficiency or operating conditions of such unit, without prior notice to and approval by the Executive Officer;

(C) failure to comply with request to test in-use DG Units within 60 days of a written request by the Executive Officer; or,

(D) failure to submit records required per section 94208 within 60 days of a written request by the Executive Officer.

(4) The Applicant failed to comply with any other requirement set out herein.

(b) A manufacturer may be denied certification or be subject to a suspension or revocation action pursuant to this section based upon the actions of an agent, employee, licensee, or other authorized representative.

(c) The Executive Officer shall notify a manufacturer by certified mail of any action taken by the Executive Officer to deny, suspend or revoke any certification granted under this article. The notice shall set forth the reasons for and evidence supporting the action(s) taken. A suspension or revocation is effective upon receipt of the notification.

(d) A manufacturer may request that the suspension or revocation be stayed pending a hearing under section 94213. In determining whether to grant the stay, the hearing officer shall consider the reasonable likelihood that the manufacturer will prevail on the merits of the appeal and the harm the manufacturer will likely suffer if the stay is not granted. The Executive Officer shall deny the stay if the adverse effects of the stay on the public health, safety, and welfare outweigh the harm to the manufacturer if the stay is not granted.

(e) Once an Executive Order of Certification has been suspended pursuant to (a) above, the manufacturer must satisfy and correct all noted reasons for the suspension and submit a written report to the Executive Officer advising him or her of all such steps taken by the manufacturer before the Executive Officer will consider reinstating the certification.

(f) After the Executive Officer suspends or revokes an Executive Order of Certification pursuant to this section and prior to commencement of a hearing under section 94213, if the manufacturer demonstrates to the Executive Officer satisfaction that the decision to suspend or revoke the certification was based on erroneous information, the Executive Officer will reinstate the certification.

(g) Nothing in this section shall prohibit the Executive Officer from taking any other action provided for by law for violations of the Health and Safety Code.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94213. **Appeals.**

Any manufacturer whose application or certification has been denied, suspended, or revoked may request a hearing to review the action as provided herein.

(a) Hearing Procedure.

Except as provided for in section 94213(b) below, any appeal pursuant to this section 94213 shall be conducted in accordance with the Administrative Hearing Procedures for Petitions for Review of Executive Officer Decisions, Title 17 California Code of Regulations, Division 3, Chapter 1, Article 2, commencing with section 60055.1.

(b) Review by written submission.

(1) In lieu of the hearing procedure set forth in (a) above, a manufacturer may request that a review of the Executive Officer's decision be conducted by a hearing officer solely by written submission.

(2) A manufacturer may request a review of the Executive Officer's decision to deny, suspend or revoke a certification no later than 20 days from the date of issuance of the notice of the denial, suspension, or revocation. Such request shall include, at a minimum, the following:

(A) name of the manufacturer, the name, address and telephone number of the person representing the manufacturer and a statement signed by a senior officer of the manufacturer warranting that the representative has full authority to bind the manufacturer as to all matters regarding the appeal;

(B) copy of the Executive Order granting certification and the written notification of denial;

(C) a statement of facts and explanation of the issues to be raised setting forth the basis for challenging the denial, suspension, or revocation (conclusory allegations will not suffice) together with all documents relevant to those issues; and

(D) the signature of the representative named in (A) above.

(3) Upon receipt of a request for review, the request shall be referred to the administrative hearing office of the state board for assignment of a hearing officer.

(4) Within 15 days of appointment of a hearing officer:

(A) ARB staff shall submit a written response to the manufacturer's submission and documents in support of the Executive Officer's action no later than 10 days after receipt of the manufacturer's submission;

(B) within 7 days of receipt of the ARB response, the manufacturer may submit one rebuttal statement which shall be limited to the issues raised in the ARB rebuttal;

(C) if the manufacturer submits a rebuttal, ARB staff may, within 7 days of receipt of the manufacturer's rebuttal, submit one rebuttal statement which shall be limited to the issues raised in the manufacturer's rebuttal; and

(D) the hearing officer shall receive all statements and documents and render a written decision. The hearing officer's decision shall be mailed to the manufacturer no later than 60 working days after the final deadline for submission of papers.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94214. **Penalties.**

In addition to suspension or revocation of certification as provided in section 94212, ARB may seek penalties under Health and Safety Code Division 26, Part 4, Chapter 4, Article 3 commencing with section 42400, for any violation of these regulations.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

Appendix B

California Senate Bill 1298 (Bowen and Peace)

BILL NUMBER: SB 1298

CHAPTERED BILL TEXT

CHAPTER 741	
FILED WITH SECRETARY OF STATE	SEPTEMBER 27, 2000
APPROVED BY GOVERNOR	SEPTEMBER 25, 2000
PASSED THE SENATE	AUGUST 31, 2000
PASSED THE ASSEMBLY	AUGUST 29, 2000
AMENDED IN ASSEMBLY	AUGUST 25, 2000
AMENDED IN ASSEMBLY	AUGUST 18, 2000
AMENDED IN ASSEMBLY	AUGUST 7, 2000
AMENDED IN ASSEMBLY	JUNE 26, 2000
AMENDED IN SENATE	MAY 28, 1999
AMENDED IN SENATE	APRIL 5, 1999

INTRODUCED BY Senators Bowen and Peace

MARCH 1, 1999

An act to add Sections 41514.9 and 41514.10 to the Health and Safety Code, relating to air pollution.

LEGISLATIVE COUNSEL'S DIGEST

SB 1298, Bowen. Air emissions: distributed generation.
(1) Existing law requires the State Air Resources Board to consider and adopt specified findings before adopting rules or regulations that would affect the operation of existing power plants. Under existing law, except as specified, any person who violates any statute, rule, regulation, permit, or order of the state board or of an air pollution control strict or an air quality management district relating to air quality, as provided, is guilty of a misdemeanor and is subject to a fine, imprisonment, or both.
This bill would require the state board, on or before January 1, 2003, to adopt a certification program and uniform emission standards for electrical generation that are exempt from district permitting requirements, and would require that those standards reflect the best performance achieved in practice by existing electrical generation technologies.
The bill would require the state board, on or before January 3, 2003, to issue guidance to districts on the permitting or certification of electrical generation technologies under their regulatory jurisdiction, as prescribed.
Since a violation of the regulations adopted pursuant to the bill would be a crime, the bill would impose a state-mandated local program.

(2) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.
This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. The Legislature finds and declares all of the following:
(a) Distributed generation can contribute to helping California meet the energy requirements of its citizens and businesses.
(b) Certain distributed generation technologies can create significant air emissions.
(c) A clear set of rules and regulations regarding the air quality impacts of distributed generation will facilitate the deployment of distributed generation.
(d) The absence of clear rules and regulations creates uncertainty that may hinder the deployment of distributed generation.
(e) It is in the public interest to encourage the deployment of distributed generation technology in a way that has a positive effect on air quality.
(f) It is the intent of the Legislature to create a streamlined and seamless regulatory program, whereby each distributed generation unit is either certified by the State Air Resources Board for use or subject to the permitting authority of a district.
SEC. 2. Section 41514.9 is added to the Health and Safety Code, to read:
41514.9. (a) On or before January 1, 2003, the state board shall adopt a certification program and uniform emission standards for electrical generation technologies that are exempt from district permitting requirements.
(b) The emission standards for electrical generation technologies shall reflect the best performance achieved in practice by existing electrical generation technologies for the electrical generation technologies referenced in subdivision (a) and, by the earliest practicable date, shall be made equivalent to the level determined by the state board to be the best available control technology for permitted central station powerplants in California. The emission standards for state certified electrical generation technology shall be expressed in pounds per megawatt hour to reflect the expected actual emissions per unit of electricity and heat provided to the consumer from each permitted central powerplant as compared to each state certified electrical generation technology.
(c) Commencing on January 1, 2003, all electrical generation technologies shall be certified by the state board or permitted by a district prior to use or operation in the state. This section does not preclude a district from establishing more stringent emission standards for electrical generation technologies than those adopted by the state board.
(d) The state board may establish a schedule of fees for purposes of this section to be assessed on persons seeking certification as a distributed generator. The fees charged, in the aggregate, shall not exceed the reasonable cost to the state board of administering the certification program.

(e) As used in this section, the following definitions shall apply:
(1) "Best available control technology" has the same meaning as defined in Section 40405.
(2) "Distributed generation" means electric generation located near the place of use.
SEC. 3. Section 41514.10 is added to the Health and Safety Code, to read:
41514.10. On or before January 1, 2003, the state board shall issue guidance to districts on the permitting or certification of electrical generation technologies under the districts regulatory jurisdiction. The guidance shall address best available control technology determinations, as defined by Section 40405, for electrical generation technologies and, by the earliest practicable date, shall make those equivalent to the level determined by the state board to be the best available control technology for permitted central station powerplants in California. The guidance shall also address methods for streamlining the permitting and approval of electrical generation units, including the potential for precertification of one or more types of electrical generation technologies.
SEC. 4. No reimbursement is required by this act pursuant to Section 6 of Article XIIIB of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIIIB of the California Constitution.

Appendix C

South Coast Air Quality Management District Method 25.3

(Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions from Clean Fueled Combustion Sources)

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

METHOD 25.3

DETERMINATION OF LOW CONCENTRATION NON-METHANE NON-ETHANE ORGANIC COMPOUND EMISSIONS FROM CLEAN FUELED COMBUSTION SOURCES

MONITORING AND ENGINEERING BRANCH
MONITORING AND ANALYSIS
March 2000

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METHOD 25.3

DETERMINATION OF LOW CONCENTRATION NON-METHANE NON-ETHANE ORGANIC COMPOUND EMISSIONS FROM CLEAN FUELED COMBUSTION SOURCES

Section 1 of 5

1. Overview and Applicability

1.1 Principle

The procedures used in this Volatile Organic Compound (VOC) source test method are similar to the approach of Method 25.1, but have been modified for the purposes of improving accuracy at low concentrations. The method eliminates positive interferences for low concentration VOC due to high levels of stack carbon dioxide and moisture. As with Method 25.1, duplicate gas samples are withdrawn from a source at a constant rate through condensate traps (traps) followed by evacuated canisters. The method differs from Method 25.1 in that stack condensate is collected at ice water (~32 °F) temperature in the traps as opposed to the lower dry ice temperature. For low concentrations, the ~32 °F traps have proven to be sufficient for trapping condensate and preventing unrecoverable VOC from being collected in the canisters. With clean sources, since the condensate consists largely of water, the traps consist of small impingers initially charged with ultra-pure water as a heat transfer medium. Interfering carbon dioxide in the traps is purged into the canisters using a ultra-pure grade inert gas. Particulate matter is prevented from interfering with the method by using an in-stack filter. Since the water does, however, have limitations on the amount of insoluble material that can be homogeneously retained, the method is limited to VOC concentrations of less than 50 ppm as carbon (ppmC) or 25 ppmC in the trap section.

VOC concentration as Non-Methane Non-Ethane Organic Compounds (NMNEOC) is determined by combining the results from the independent analyses of the condensate in each trap and the gas in its associated canister. The traps are analyzed for total organic carbon by liquid injection into an infra-red total organic carbon analyzer. The canisters are analyzed for NMNEOC using the Method 25.1 approach. The analysis consists of foreflush and backflush of a gas chromatography (GC) column followed by an oxidizer, methanizer, and a flame ionization detector (FID). The GC separates the VOC component from the sample; the oxidizer converts the VOC to carbon dioxide; the methanizer converts the resulting carbon dioxide to methane. The results are determined by the FID in units of parts per million by volume as carbon (ppmC). Carbon monoxide and fixed gases (carbon dioxide and oxygen) can be determined by analysis of the canister portion of the sample by SCAQMD Method 10.1.

The method is written to represent the configuration used during validation testing. Mention of trade names in this source test method does not constitute endorsement by SCAQMD; the model names and numbers are given as those used during the validation phase of the method. Other manufacturers of equipment may be used subject to demonstration of equivalency as approved by the SCAQMD.

A bias correction factor of 1.086 must be applied to the final results of this method. The use of this bias correction factor is required by the USEPA as determined during the validation phase of the method (refer to Section 5.3).

1.2 Applicability

This method replaces the method that was formerly known as SCAQMD Draft Method 25.2. Former Draft Method 25.2 has been removed from consideration due to inherent shortcomings in its approach which have been proven to cause both a low bias and poor precision. **Source test results achieved by former Draft Method 25.2 are, therefore, not considered as valid for SCAQMD purposes.**

Method 25.3 measures low concentration VOC emissions as NMNEOC expressed as ppmC. Since it is not adversely affected by the unpredictability of VOC composition in combustion products, the method is particularly applicable to combustion processes. In its total carbon approach, the method is not affected by compound specific instrument response factor variables often encountered in other detection methods. This method is applicable when the following conditions are met:

1. Combustion sources must use clean fuels. Clean fuels are defined as natural gas, refinery fuel gas, butane, LPG, landfill gas, digester gas, methanol and ethanol.

2. The resulting concentration as measured by this method must be less than 50 ppmC or alternatively 25 ppmC in the trap portion with a higher limit on the canister portion evaluated case by case depending on the compounds present.

Supporting data has shown that for concentrations above 50 ppmC (or 25 ppm in the trap) or for non-clean fueled combustion sources, a bias will occur due to limitations in the condensate trap design (see *Interferences*). For these situations, refer to Method 25.1.

The method may be applied to sources of higher concentrations where exclusively water soluble VOC is encountered. The applicability of the method to these situations must be evaluated by the SCAQMD on a case by case basis.

The method may be used without the condensate trap and its associated procedures only for ambient temperature sources where no combustion products or other sources of moisture other than ambient are present. Additionally, the resulting concentration as measured by this method must be less than 50 ppmC. The applicability of the method to these situations must be evaluated by SCAQMD on a case by case basis.

The lower detection limit of the method is 1 ppm NMNEOC as carbon.

For determining mass emissions, a molecular weight per carbon ratio must be established to account for bonded oxygen, hydrogen, chlorine, or other elements. Similarly for converting ppmC to actual ppm, the average carbon number must be estimated. Section five of this method provides guidelines for determining molecular weight per carbon.

This method assumes that methane and ethane are the only significant VOC exempt compounds commonly found in combustion exhausts. The NMNEOC results can be corrected for other exempt compounds when present, using an appropriate method approved by SCAQMD, CARB, and EPA for determining exempt content.

1.4 Limitations and Interferences

In cases where combustion type control devices are used to control streams containing exempt compounds as specified in SCAQMD Rule 102, a positive bias towards VOC will occur if a correction is not made for the presence of exempt compounds.

Supporting data has shown a potential negative bias when sampling streams of over 50 ppmC due to design limitation of the condensate traps which were designed for lower concentrations. This is believed to be caused by non-homogeneity in the water traps with insoluble species present.

Sampling combustion sources burning non-clean fuels can cause a negative bias. This is also due to limitations in the low-concentration trap design combined with the presence of high molecular weight, semi-volatile, condensable, insoluble material which tends to separate from the water in the trap.

Ammonia present in concentrations above 15 ppm can reduce the level of precision of this method but does not cause a specific low or high bias.

Because of the low concentration of VOC encountered, contamination present can cause a significant bias. The procedures of this method have been designed to eliminate potential contamination. It is, however, imperative that the equipment cleaning and sample handling procedures are carefully followed.

If samples are extracted from a stratified stream, a positive or negative bias may occur. Samples must be extracted from well mixed locations or employ multi-point sampling (see *Field Procedures*).

Procedures for minimizing the effects of any of the above interferences where applicable are not all addressed in this method. Alternative procedures must be evaluated on a case by case basis and are subject to SCAQMD approval.

METHOD 25.3

DETERMINATION OF LOW CONCENTRATION NON-METHANE NON-ETHANE ORGANIC COMPOUND EMISSIONS FROM CLEAN FUELED COMBUSTION SOURCES

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2. Sampling Apparatus and Field Equipment Preparation

2.1 Sampling Apparatus

The sampling system consists of an in-stack filter, a probe, a Teflon line, a condensate trap, a flow controller, a vacuum gauge, a valve, and a canister (see Figure 25.3-1). The sampling equipment can be constructed from commercially available components. The internal volume of the entire sampling apparatus excluding the canister must not exceed one percent of the canister volume in order to avoid dilution by the sample system dead space. The following is a detailed description of the sampling system component requirements.

a. In-Stack Filter

A ≤2 micron, 316 type stainless steel or other high temperature non-corrosive material filter located at the stack end of the probe tip. The filter can be the small frit type inserted into a 0.25 in. tube fitting connected to the probe tip.

b. Probe

Seamless stainless steel tubing, 0.25 in. outside diameter and cut to a length of half the stack diameter or sufficient length to extend near the stack or duct center to avoid dilution effects from the sampling port. When sampling, the probe is fixed with the connector line end flush with the port entrance so that the stack gases heat the entire probe length.

c. Condensate Trap

The condensate trap is designed as a small 4 ml glass bodied impinger. The body is a commonly available 4 ml narrow screw top glass vial which is used not only as the trap body but also for sample storage with its supplied Teflon lined screw cap. The approximate dimensions of the vials are 1.8 in. total height, 0.6 in. o.d., and 0.3 in. i.d. at the upper threaded opening. A 0.25 in. hole must be made in a spare screw cap for affixing the condensate trap to the sampling assembly. Size 009 and a size 006 Viton "O" rings are used to seal and retain the glass vial to the sampling assembly. See Figure 25.3-2 for specifications on condensate trap design. For sampling, the condensate trap is charged with approximately 2 ml of hydrocarbon free water. The 4 ml trap size is sufficient for stack moistures of up to 25% by volume. For higher stack moistures, the trap design must be scaled up accordingly.

d. Connector Line

Seamless Perfluoroalkoxy (also known as PFA, a type of Teflon) tubing, 0.125 in. outside diameter x 0.026 in. wall thickness and cut to length of no more than 18 in. The connector line is connected to the probe with a stainless steel tube reducer. The other end of the connector line must extend into the condensate trap with a tapered end having an opening of less than 0.020 in. so that small bubbles are formed in the condensate trap. This tapered end can be formed by applying a point source of heat to approximately one inch of a continuous section of tubing so that the temperature of the section is heated to near the melting point. The opposite sides of the heated section can be pulled apart while twisting torsionally to form a split at the heated section. The narrow tips created at the ends of the tubing split can then be trimmed appropriately to create the small opening. When assembled, the tubing extends from the probe reducer to within 0.125 in. from the bottom of the condensate trap as shown in Figure 25.3-2.

e. Ice water bath

A container is affixed to the sampling apparatus to hold ice and water used to cool the condensate trap. The ice bath must be of sufficient cross section to surround the condensate trap with an appropriate amount of ice to maintain the ice water temperature (minimum 2.5 in. diameter). The ice bath must be approximately one inch in height (for 4 ml trap size) so that the condensate trap vial connection remains above the top of the ice bath container and the overflowing cold water will be below the connector level. This is done to eliminate the risk of contamination. The ice bath must also be positioned sufficiently high so that the water level of the bath is higher than the water level inside the condensate trap.

f. Flow Rate Controller

A vacuum flow regulator, rotameter, fine orifice, or other flow regulator capable of maintaining a constant flow rate (± 10%) at the probe tip over the sampling period. The flow controller is located downstream of the condensate trap so that its function is unaffected by the condensate. For flows regulated by rotameters or orifices with a control valve, the control valve will require constant adjustment during sampling due to the declining pressure differential. The control valve must be located between the canister and the rotameter or orifice. For a critical orifice, where a control valve is not used, sampling must be terminated if the vacuum in the canister drops below the level where a constant flow cannot be achieved. This type of orifice can be prepared using a GC syringe needle fixed concentrically into 1/4 in. stainless steel tubing. Epoxy or silicone adhesive has been successfully used for this purpose. The desired flow rate for one hour sampling time for a 6-liter canister is ~70 ml/min and can be achieved using a short (appropriate) length of 0.0045" syringe needle. The flow rates can be fine tuned by adjusting the length of the inner needle tube.

g. Vacuum Gauge

A stainless steel gauge cleaned for electronic use is specified for monitoring vacuum in the tank and sampling system between the flow controller and sample flow valve both during sampling and leak checks (0 to 30 in. Hg Vacuum).

h. Sample Flow Valve

Stainless steel bellows valve is used for starting, stopping, or regulating sample flow and is located between the vacuum gauge and sample canister.

i. Sample Canister

The electro-polished stainless steel canister has a volume of 6 ± 0.5 liters. The canister volume is determined to the nearest 10 ml as described in section 3.8.

i. Sampling Assembly

The assembled sampling apparatus in its "ready for transport" configuration is shown in Figure 25.3-1. An exploded view of the sample line and condensate trap assembly is shown in Figure 25.3-2. A stainless steel quick connector is useful for connecting and disconnecting the canister from the remainder of the sampling assembly.

2.2 Sampling Reagents

The condensate trap is initially charged with approximately 2 ml hydrocarbon free water such as deionized or distilled water. This water must have a TOC content of less than one ppmC.

2.3 Sampling Equipment Preparation

2.3.1 Sampling Equipment Cleaning

The sampling equipment preparation must be performed in a clean indoor laboratory type environment and not in the field. All equipment that contacts the sample excluding the canister, but including the remaining equipment listed in section 2.1 and other equipment that contacts the sample such as connectors and end caps, must be thoroughly cleaned as follows: Soak the equipment in non-residue, rinsable type laboratory glassware detergent and water. Scrub all accessible surfaces and remove all visible surface residues. Rinse the equipment thoroughly first with tap water then with deionized water. At this point onward, be certain not to touch any part of the internal sample path or open connection ends with any object that has not been cleaned using the above procedure and particularly not at anytime with hands or fingers. Use powder-free latex gloves while handling cleaned equipment. Blow the equipment pieces dry with ultra-pure grade air (< 0.5 ppm hydrocarbon) while holding the pieces by the outside surface which does not contact the sample. Under no circumstances should uncleaned compressed air be used for drying parts due to the possibility of entrained compressor lube oil or other droplets causing contamination. After drying, the equipment excluding the canister can be assembled as in Figure 25.3-1 using a clean empty glass vial on the condensate trap assembly during transportation to the field. Clean the probe and filter assembly by exposing to elevated temperatures using an open flame while passing air through the assembly. Gradually move the flame along the entire length of the probe at a rate so that the probe is heated to a glowing orange in each section contacted by the flame, then allow to cool. Seal the open ends of the probe and sampling assembly using a clean cap or foil.

2.3.2 Canister Preparation

The following equipment are needed for canister preparation:

a. Manometer

Must be capable of measuring pressure to within 1 mm Hg in the 0-900 mm range. Manometer must be NIST traceable.

b. Vacuum Pump

Capable of producing a full 30 in. Hg of gauge vacuum (<10 mm Hg. absolute pressure). This is to evacuate the sample tanks and intermediate collection vessels (see Sections 3.3 and 3.4).

Do not use canisters previously used for other types of sampling where concentrations of >50 ppmC were encountered. Clean the Summa polished canisters by sequential filling with pure nitrogen gas and evacuating to approximately 3 mm Hg. It has been determined that ten cycles are sufficient to result in a <1 ppmC for a pure nitrogen blank check. After the last cleaning cycle, fill the canister with pure nitrogen gas to ~900 in. Hg then allow it to set overnight. Perform a tank blank analysis on the nitrogen gas in the canister as in Section 4. The backflush concentration should be 0.5 ppmC or less, otherwise repeat the cleaning-blanking process. Finish the cleaning process by filling the canister with pressurized gas, and then evacuating the canister to ~ zero mm Hg. The laboratory can establish a cleaning procedure without the blank test on the basis of the history of the canisters used and previous data on the cleaning-blanking process. Save the data for future QA/QC SCAQMD audits.

The sample tank is leak checked by isolating it from the vacuum pump and allowing the tank to sit for at least 10 minutes. The tank is acceptable if no change in tank vacuum is noted.

2.3.3 Condensate Trap Vial Preparation

Store 200 to 300 ml of the hydrocarbon free water in a clean glass jar with a glass stopper at normal refrigerator temperature (approximately 5 ^{o}C). Analyze the water for TOC content at ice water temperature as in Section 4. If the TOC content is less than 1 ppmC, keep the water for future use. If the TOC content is more than 1 ppmC, replace the water, and repeat the process. Label both a clean threaded 4 ml glass vial and a threaded cap as a set. Tare and record the vial and cap set. Fill the vial with ~2 ml of the hydrocarbon free water (approximately half full) and tightly replace the corresponding cap. Prepare an adequate number of vials for the deployment of the duplicate samples that will be collected. Extra vials must be prepared for reagent blanks and connector line rinses. It is important that plenty of water from the same batch is left in the stoppered glass jar for use during analysis. The vials and the remaining water in the stoppered glass jar are then stored at refrigerator temperature in the laboratory until transport to the field.

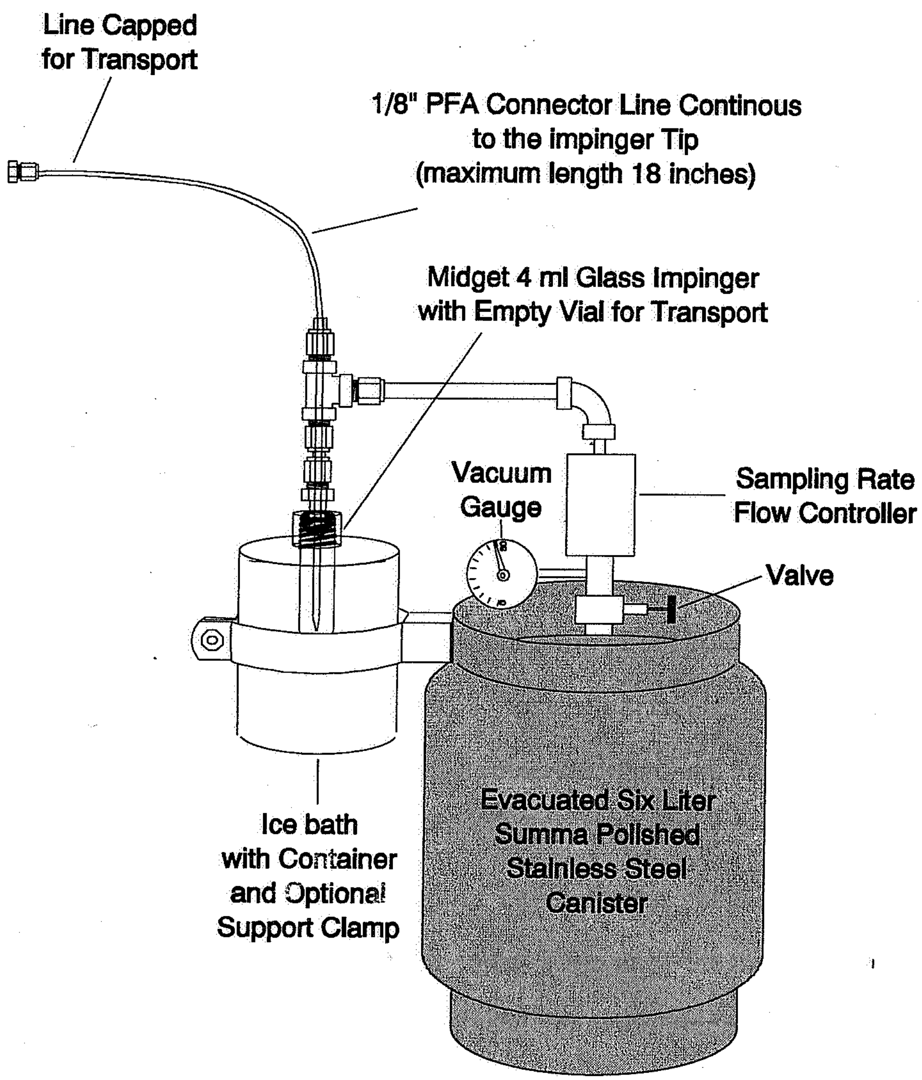

Figure 25.3-1 Preparation of Sampling Apparatus

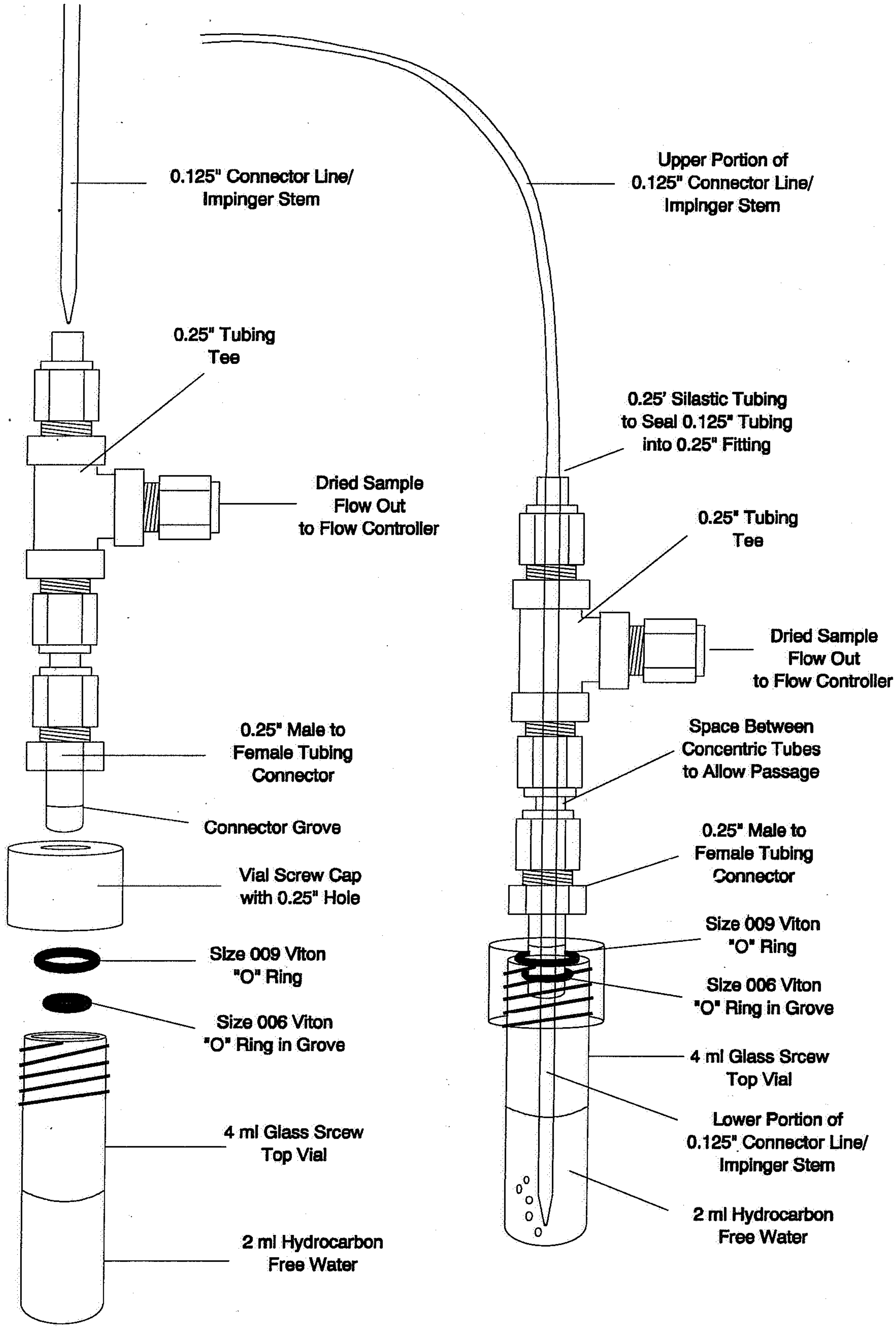

Figure 25.3-2 Condensate Trap Detail

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3. Field Procedures

Individual sampling runs shall consist of duplicate simultaneous samples as described in this section. The descriptions are provided for individual samples in the duplicate set for purposes of simplicity. Condensate trap blanks are required for use during analysis. By following the equipment cleaning and canister preparation procedures, full field blanks are not required but may be employed if deemed necessary. Field blanks would consist of a full sampling assembly handled and analyzed identically to the actual samples with the exception that samples are not drawn into the containers. Results from sampling must not be corrected using either field blanks or any type of ambient sampling for reporting purposes. The results from either field blanks or ambient samples may be reported along with the sampling results.

3.1 Pre-test Determinations

Samples must be taken at well mixed and uniform locations, i.e. far from situations causing stratification such as duct junctions, addition of dilution air, combustion zones, or other flow disturbances that may alter the concentration profile. Alternatively, an approved stratification check (refer to SCAQMD Source Test Manual Chapter X) using a portable hydrocarbon analyzer may be used to check for stratification of less than 10% or for a representative sampling point within a stratified duct. Multi-point sampling can alternatively be employed but will require multiple concurrent samples with associated probe lengths due to in-stack probe heating requirements.

The required sampling time interval is dependent on the applicable rule or permit condition that is to be evaluated. In most cases when not specified, a full one hour sampling period will be required since results will be used to determine emissions in lb/hr.

Sampling should begin and end only when the process has been operating for a sufficient length of time and steady state operation can be assured. A steady state is defined as operating at constant operating temperature, feed rate, fuel rate, product application or throughput rate, etc., and that the production rate is steady throughout the process. For batch or cyclic processes, the sampling period must encompass at least one complete cycle or batch. The sampling period must also begin and end at the same point in the cycle so that portions of the cycle are not over or under-represented.

3.2 On-site Equipment Assembly

Once in place at the sampling location, the equipment can be assembled as shown in Figure 25.3-3 with the probe connected but not inserted into the stack. Care must be taken during this step to avoid contamination of the internal surfaces of the condensate trap parts by any contact with objects or dust in the area. The condensate trap water vials must be chilled for a minimum of 5 minutes before sampling. The chilled condensate trap vial is attached by removing the empty vial placed on the assembly during transport and replacing with the water filled sample vial. The empty vial is then capped with the water vial lid so that the combination is kept clean while not in use during sampling. Once the vial is attached to the condensate trap assembly, the equipment must remain in the upright position so that the condensate trap water does not drain out of the condensate trap assembly into the flow controller.

The condensate trap can then be positioned with ice in the ice bath The position of the ice bath relative to the condensate trap is such that the vial connection will be above the top of the ice bath container so that the overflowing ice and cold water will be below the connector level. The ice bath must also be positioned sufficiently high so that the water level of the bath is higher than the water level inside the condensate trap. After completing the assembly, record the vial and canister identification numbers on the field data sheet as in Figure 25.3-4.

3.3 Pretest Leak Check

A pretest leak check is required. After assembling the sampling system as shown in Figure 25.3-3, make certain that the fitting at the probe that holds the in-stack filter is tightly capped. The leak check is performed by opening and closing of the sample flow valve so that the valve is partially open for a sufficient amount of time to introduce the canister vacuum to the remainder of the system. Immediately after the sample flow valve is closed, the vacuum gauge may initially drop numerically in vacuum if a restricting orifice is used as a flow controller. The vacuum drop should cease at numerically above 10 in. Hg. At this point a cease in movement of the vacuum gauge for a period of ten minutes indicates an acceptable leak check on the sampling system. Additionally, when sampling is initiated, the vacuum gauge must indicate a canister vacuum of numerically greater than 28 in. Hg. If this initial vacuum is numerically less than 28 in Hg, a leak in the canister subsequent to its evacuation is indicated.

3.4 Sampling Operation

Uncap the filter fitting at the probe tip and place the probe in the stack with the opening of the probe tip tangent to the stack flow. Clamp or fasten the probe in place so that the entire stainless steel probe is within the heat of the stack and as far into the stack as possible while avoiding melting the PFA connector line. The purpose of this probe placement is to ensure that no condensation occurs in the probe. Condensation in the PFA connector line is, however, acceptable. If present, the condensation should begin to form after the junction of the probe to the PFA connector line. This can be verified by visual observation of the condensation through the semitransparent PFA material. Clean the port as much as possible before inserting the probe. When inserting the probe into the stack, care must be taken so that the probe opening does not contact the stack port internal surface residues or residues on the internal stack wall. Seal the port around the probe so that ambient air does not dilute the stack gases.

If the process that is being sampled is operating under normal representative operating conditions or the conditions specified by the permit conditions, sampling may begin. To begin sampling, open the sample flow control valve and maintain a steady flow that varies by no more than 10% so that the canister is filled from its full 30 in. Hg vacuum to a numerical vacuum of 2 - 15 in. Hg over the specified sampling period as determined in section 2.3.

Immediately after sampling has commenced, record the initial canister vacuum and clock time. If this initial vacuum is numerically less than 28 in. Hg, then the sample is invalidated. Provide ice in the ice bath during sampling to maintain a constant ice bath temperature of ~32 ^{o}F. Record the canister vacuums at regular intervals (15 minute recommended) during sampling as an indicator of constant flow into the canisters. Fill in the remaining information as prompted by the field data sheet in Figure 25.3-4. At the end of the sampling period, record the final vacuum and clock time, then close the sample flow valve. Remove the probe from the stack, note the condition of the in-stack filter, and recap the probe at the filter fitting.

If the sampling is interrupted due to a shutdown in the process being sampled or for an upset of normal or specified operation, close the sample flow valve to interrupt sampling. Record vacuum gauge readings and clock time. When the source resumes the normal or specified operating conditions, sampling may resume by reopening the sample flow control valve.

3.5 Reference Point Velocity

If a flow rate is to be measured for determining mass emissions, monitor velocity at a reference point during sampling. Take velocity readings at five minute intervals during the sampling period, or more often when the velocity or temperature fluctuates by more than 20 percent. Use the ratio of average reference point readings during sampling to average reference point readings during the traverse to correct the average stack velocity during the traverse. This is done so that average concentration measured during sampling corresponds to the average flow rate experienced during sampling.

3.6 Post Test Procedures

Immediately after sampling, perform a post test leak check as in section 2.6 with the maximum vacuum that can be achieved with the vacuum remaining in the canister.

After the post-test leak check, disconnect the PFA line from the probe. Rinse the condensate present in the line into the condensate trap with 0.5 to 1.0 ml of hydrocarbon free water. This is accomplished by introducing a small amount of the remaining tank vacuum to the line while dipping the open end of the line briefly into a spare vial of the hydrocarbon-free water. During this step, observe the water level in the trap and avoid over-filling the trap to avoid the water being drawn into the flow controller. After the connector line has been flushed, the condensate trap body is disconnected, capped, sealed, and stored at approximately 32 °F. Alternatively the connector line can be capped and the condensate trap left connected to the sampling assembly. If the condensate trap is left connected, it does not need to be stored at 32 °F but must not be allowed to exceed 85 °F.

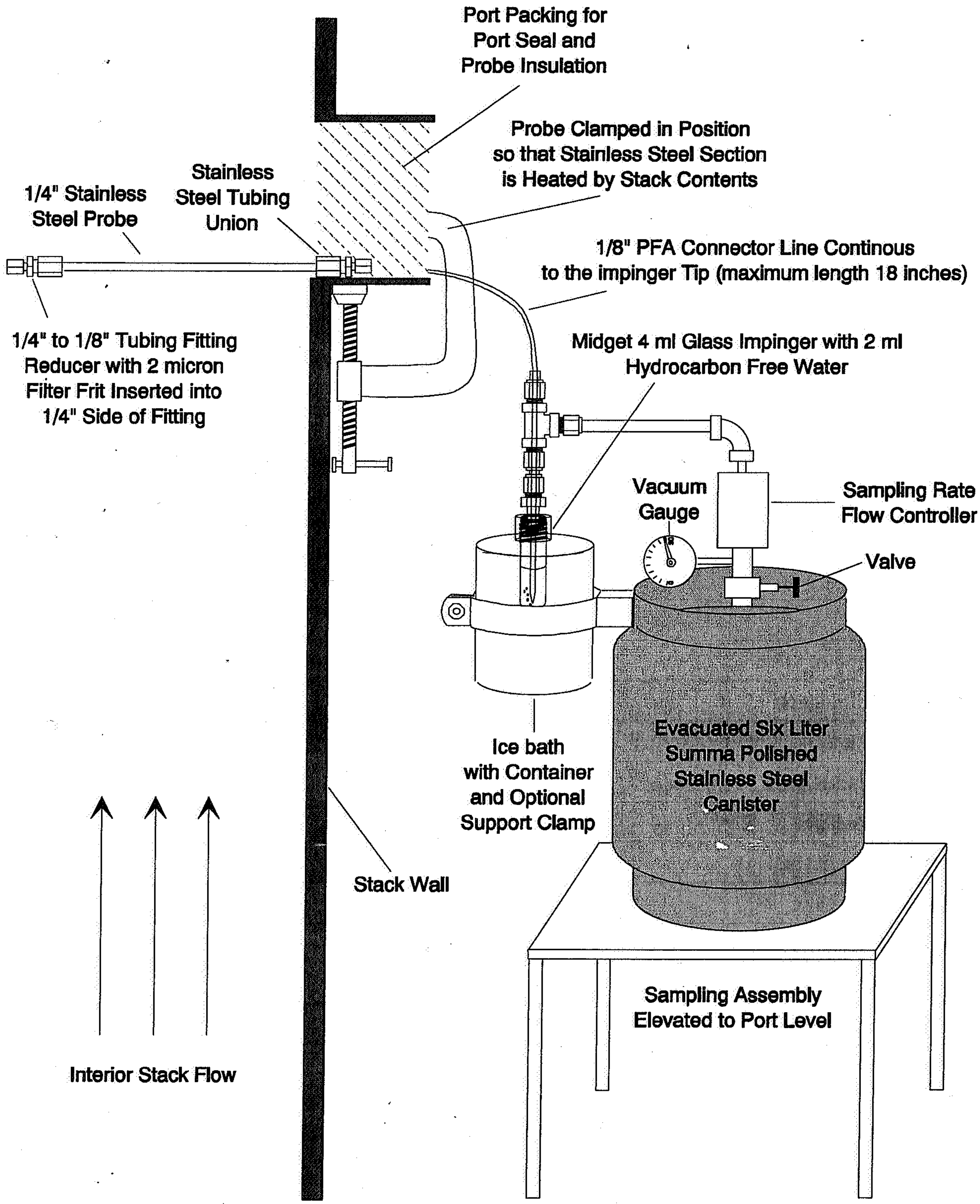

Figure 25.3-3 Sampling Apparatus During Sampling

Test No.________________ Date______________

Company Name________________________________ Recorded by______________

Sampling Location____

METHOD 25.3 FIELD DATA SHEET

Pre-Test Leak Check:
Gauge Vacuum_____/_____in. Hg
Loss in 60 seconds_____/_____in. Hg

Post-Test leak Check
Gauge Vacuum:_____/_____in. Hg
Loss in 60 seconds:_____/_____in. Hg

Reference Point #_________

Sample Data

	Sample #1	Sample #2
Canister No.		
Trap No.		
Controller No.		
Location within Stack		
Initial Time		
Initial Vacuum (in. Hg)		
Intermediate Time		
Intermediate Vacuum (in. Hg)		
Intermediate Time		
Intermediate Vacuum (in. Hg)		
Intermediate Time		
Intermediate Vacuum (in. Hg)		
Final Time		
Final Vacuum (in. Hg)		

Reference Point Data

Time	Velocity Head (in.H_20)	Temperature (°F)

Observations____

Figure 25.3-4 Field Data Sheet

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4. Laboratory Procedures

The analyst must demonstrate prior to initial use that each of the analyzers used in this method is capable of measuring low concentration NMNEOC. For the canister analysis this includes a demonstration of proper separation, oxidation, reduction, and measurement. This demonstration must also prove that the equipment can resolve lower concentration standards at just above the lower detection limit (1 ppm) of this method. Achieving low concentration analysis for NMNEOC by this method requires contaminant free equipment, an appropriate baseline subtraction, and an appropriate range of calibration. This demonstration of the analyzers' performance must be approved by the SCAQMD laboratory for use in this method.

4.1 Sample Receipt

a) Check the correctness of labels, number of samples vials, number of canisters, and "Chain of Custody" forms for completeness of information.

a) Inspect the water sample vials for leakage. The canister gauge reading (if equipped) should be 2 -15 in. .Hg, otherwise make a note.

a) Sample delivery personnel sign and date to relinquish the samples.

a) Laboratory personnel sign and date to receive the sample.

a) Store the sample vials in a clean refrigerator, and the canisters in a secured area. The vials must be purged within 24 hours from sampling. The analysis must be performed within ten days from sampling.

4.2 Sample Purge

a) Allow the sampling canisters to equilibrate to room temperature; then, using the calibrated high precision manometer specified in Section 2.3.2(a), measure the pressure of each canister to the nearest 1 mm Hg. The pressure should be similar to the final sampling pressure as indicated by the sampling gauge. If a significant pressure loss is observed indicating a leak, invalidate the sample. Invalidate the sample when the absolute return pressure is less than 200 mm Hg. Record this pressure as return pressure (Pr) before proceeding to the purge step.

b) Reassemble the sample vial to the remainder of the sampling assembly. If the condensate trap vial was left connected to the sampling apparatus, it must be quickly capped when disconnected to check canister vacuum, and kept upright until reconnection after the received pressure has been taken. When the sampling apparatus is reassembled, a leak check must be performed as in Section 3.3.

c) Connect the probe tip to a source of ultra pure grade nitrogen or argon and introduce a flow of slightly greater than that of the sampling rate at the ultra pure gas source. The gas source must contain a tee that is open to the atmosphere such that excess pressure is bled to the atmosphere. Refer to Figure 25.3-5 for a schematic of this configuration.

d) Open the sampling canister valve and allow the pure gas to purge through the assembly and into the canister. The minimum purging gas flow rate is 25 to 30 ml/minute. The bubbling characteristics should be similar to that encountered during sampling. Allow the gas to purge for 10 minutes or until the vacuum drops to 2 in. Hg numerically lower than the received vacuum.

e) After the purge period, close the purge gas valve first and allow any residual pressure to vent through the purge gas line tee before closing the canister valve to avoid back flushing the condensate trap assembly.

f) Remove the sample vial and cap securely. The glass vial is then analyzed for TOC or stored at refrigerator temperature until analysis.

g) Remove the sampling assembly then pressurize the canister with pure argon or nitrogen gas to a pressure between 860-910 mm Hg. Shut off pressure from pure gas source, wait until reading is stable, record the reading as final pressure (Pf).

h) Disconnect the canister from the purge gas line and seal. The sample canister is analyzed by TCA or stored until analysis.

4.3 Apparatus and Reagents for TOC Analysis on the Traps

4.3.1 Shimadzu TOC-5000 Analyzer

The TOC-5000 analyzer is automated. Total organic carbon (TOC) is measured by the difference between total carbon (TC) and inorganic carbon (IC). TC, containing both organic and inorganic carbon, is measured by oxidizing an aliquot of sample with a Platinum catalyst at 650 ± 5 °C using an air carrier/ oxidizer. The CO2 gas is quantified against the stored calibration curve by a non-dispersive infra-red (NDIR) detector. IC is measured by injecting an aliquot of sample into a phosphoric acid (H_3PO_4) vessel. The CO_2 released from acidification of inorganic carbonaceous compounds with the acid is sparged with air and then quantified the same way as CO_2 from TC. The difference of the two results is TOC.

4.3.2 Other Apparatus and Reagents for TOC Analysis

250 ul glass syringe

Glass vials, 4 and 15 ml size with Teflon lined screw caps

Refrigerator set to a temperature of approximately 5 °C

Ice water bath

Analytical balance capable of weighing to 0.1 mg

Laboratory glassware as need

Deionized (DI) water containing <1 ppmC TOC

Potassium hydrogen phthalate (KHP), AR grade or equivalent

Sodium carbonate, A.C.S. grade or equivalent

Sodium hydrogen carbonate, A.C.S. grade or equivalent

Three to six volatile organic compounds, with known purity, representing the expected organic class of compounds in the sample

Ultra zero air containing <0.1 ppmC

4.4 Preparation of Standards and Reagents for TOC Analysis

The following Equation (1) can be used for preparing a known carbon stock standard with any pure carbonaceous compound:

$$\text{mgC/Kg (ppmC)} = (W_t \times n \times A_c \times 1000 \text{ mg/g}) \times 1000 \text{ g/kg}/(MW \times W_s) \quad (1)$$

W_t = weight of compound in grams

n = number of carbon atoms per molecule

A_c = atomic weight of carbon

MW = molecular weight of the compound

W_s = weight of solution (100 g)

Note: in the TOC analysis section only, ppm is on a weight basis

For a 1000 ppmC TOC stock standard, mix 0.2125 g KHP with a balance of DI water and make 100g of solution. Cap tightly, and store in a refrigerator. Discard after two months.

For a 1000 ppmC TC stock standard, mix 0.3497 g $NaHCO_3$ and 04412 g of Na_2CO_3, with a balance of DI water to make 100 g of solution. Cap tightly, and store in a refrigerator. Discard the solution if a fibrous or flaky material appears.

Prepare working standards for TOC from the stock standard solutions; accurately weigh aliquots of stock standard in a tarred 15 ml size, screw cap vial. Add DI water to about 80% capacity, reweigh the total solution. Calculate the concentration of working standard using Equation 2:

$$\text{ppmC of working standard} = \text{ppmC stock standard} \times W_s/W_{ts} \quad (2)$$

where W_s = weight in grams of stock standard

W_{ts} = weight in grams of total solution

The recommended concentrations for TOC working standards are 10 ppmC, 40 ppmC and 100 ppmC. TC standards are prepared in the same manner.

A TOC mixture for QC (QC standard) is prepared in the same manner as the standards choosing organic compounds in the same class that represent the expected compounds in the sample. The content of the stock solution may not be given in units of ppmC for an individual component. For example, formaldehyde in water contains 37% formaldehyde. Add concentrations of individual components to get the total concentration as carbon.

4.5 TOC Analysis of Traps

a) Take the sample vials including field blank from the refrigerator one at a time, wipe off any water on the vial prior to opening.

b) If less than 4 ml of water is present in the vials, open each vial add DI water (which had been used for pre-field sampling preparation) to ~4 ml, cap the vial, and allow it to equilibrate to room temperature.

c) Dry each sample vial, and weigh. Return all vials to the refrigerator.

d) The TOC analyzer is calibrated, prepared for sample analysis, and run according to Manufacturer's Instruction Manual. The following steps are applied generically the TOC analysis.

e) Prepare an adequate ice-water bath and replenish ice as required during the entire analysis.

f) Each analytical run for all DI water blanks, standards, field blanks, samples, and controls consists of three injections/run with three wash cycles. These are all performed at ice-water bath conditions. Perform the first run using the laboratory DI water as a cleanup and a lab blank. Run the DI water until the average TOC of three injections is less than 1 ppmC by using the previously stored calibration files.

g) Run TOC and TC standards and store in the calibration files according to the calibration instruction in the manual. Multiple calibration files can be stored for the various levels anticipated. Experience has shown that it is not required to run new standards and new calibration on every batch of samples.

h) For each batch, initially check the validity of stored calibrations by running a TOC and a TC standard at expected concentrations. Rerun the standard solutions if the average area count of a standard is greater than ±2% of the calibration.

i) The analysis for each batch of samples is run in the following order:

Run a QC standard in the range of expected concentration.
Run the field blank.
Run the samples.
Run QC standards that bracket the sample concentrations.

4.6 TOC Analysis Quality Assurance (QA) Criteria

a) The precision of the TOC analysis must be 10% or less as determined using the percent coefficient of variation (COV) from the three injections calculated as follows:

COV = 100 x (standard deviation / mean)

Where: The standard deviation of TOC is determined from the square root of the sum of the squares of the standard deviations for TC and IC.

b) Accuracy of the QC sample as % difference from the prepared concentration must be within ±10%.

c) TOC of the field blank concentration can be reported along with the results but not used to correct the results. The field blank is typically equal or higher than lab DI water blank (typically ~ 1 ppmC).

d) IC concentration of sample should be less than 10 ppmC (typically ~2 to 5 ppmC), otherwise, make a note on the report.

4.7 TOC Calculations

Subtract the laboratory DI water blank TOC (not field blank) from the average of the three sample analyses to yield a result for TOC in ug/ml of condensate trap water (C_i). Calculate the amount of organic carbon as part per million by volume (ppmv) as gaseous carbon in the sample using the following equation:

$C_w = (C_i \times V_i \times P_a \times V_{id})/(V_c \times P_r \times A_c)$

where:

A_c = Atomic weight of carbon (12.01 g/mol)

C_w = gaseous concentration of TOC as ppmv in condensate trap water

C_i = TOC concentration in ug/ml of condensate trap water (Assume TOC concentration ug/g = ug/ml at 4°C)

V_i = volume of condensate trap water in ml

V_{id} = volume of ideal gas per mole at 25°C (24.4652 liters/mole)

V_c = volume of the SUMMA canister in liters

P_a = atmospheric pressure in mm Hg (760 mm Hg)

P_r = return pressure in mm Hg

4.8 Apparatus and Reagents for TCA Analysis by GC/FID on Canisters

4.8.1 TCA System

The Total Combustion Analysis (TCA) system consists of gas chromatography (GC) modified with a backflush valve with reversed flow capability for back-flushing the trapped NMNEOC. It is also equipped with a catalytic oxidizer, a catalytic reducer, a flame ionization detector (FID), and a data handling system. A gas sample is injected, using a 1 ml fixed loop 6-port gas injection valve, onto a dual packed column. The NMNEOC analyzer is a semi-continuous GC/FID analyzer capable of: (1) separating carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4), and NMNEOC, (2) oxidizing the NMNEOC to CO_2, and CO to CO_2, (3) reducing the resulting CO_2 to CH_4, (4) quantifying the CH_4, and (5) after ethane elutes from the GC column, the column is heated and backflushed to release remaining organic compounds. The resulting CH_4 is quantified against a stored standard curve by the FID detector. See Figure 25.3-6 for a flow chart of the instrument. The instrumentation system flow diagram is shown in Figure 25.3-7.

The analytical equipment are available commercially or can be constructed from available components by a qualified instrument laboratory. The analyzer consists of the following major components:

a. Sample Injection System

A heated six-port valve injector fitted with a 1 ml sample loop is recommended. The sample loop consists of a sufficient length of 1/16 in. stainless steel tubing so that the desired internal volume is achieved. The installation of the valve is depicted in Figure 25.3-7. The sample injection port and sample loop must be equipped with a heating mechanism that maintains the specified temperature of 150 ± 5 °C. The six port valve is located in the column oven.

b. Separation Column(s)

The gas chromatographic system consists of a two part column capable of separating carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4), and NMNEOC. The two part column consists of Tenax GC 80/100 mesh in a 1 ft. length of 1/8 in. stainless steel tubing, in series with Chromosorb 106 80/100 mesh in a 6 ft length of 1/8 in. stainless steel tubing. The NMNEOC is trapped in the Tenax section of the column while the remaining compounds are eluted through the Chromosorb section. The backflush procedure is also performed through both sections of the column. The column is contained in an oven capable of performing the temperature ramping as specified in Section 4.9. A heated four port valve is used to control flow direction through the column as shown in Figure 25.3-7.

c. Oxidation Catalyst

A catalyst system capable of oxidizing CH_4 to CO_2 with at least 95 percent efficiency is acceptable. The oxidation catalyst system consists of 15% chromium III oxide on 4 mm alumina pellets packed in the center 4 in. section of a 12 in. length of 1/4 in. diameter Inconnel tubing. The remaining space on both ends of the tubing is packed with quartz wool for retention of the catalyst. The oxidation catalyst is contained within a heating device capable of maintaining a temperature of 650 ± 5 °C. A four port valve is used to control flow during either oxidation or regeneration modes of the oxidation catalyst. The installation of the valve is depicted in Figure 25.3-7.

d. Reduction Catalyst (Methanizer)

A catalyst system capable of reducing CO_2 to CH_4 with at least 95 percent efficiency is acceptable. The reducing catalyst consists of nickel on Gas Chrom R 80/100 mesh. To prepare the material, first dry the Gas Chrom R 80/100 at 120 °C overnight. Allow to cool to room temperature in a dessicator. Dissolve 1 g of nickelous nitrate in 30 ml deionized water. Slowly add 10 g of the dried Gas Chrom R 80/100 mesh with constant stirring. Heat to dryness on a hot plate, then dry overnight at 230 ± 5 °C. Allow again to cool to room temperature in a dessicator. The catalyst is then packed in the center 4 in. section of a 12 in. length of 3/16 in. diameter Inconnel tubing. Each of the remaining space at either end of the tubing is packed with quartz wool. The reduction catalyst is contained within a heating device capable of maintaining a temperature of 380 ± 5 °C. Reduction gas (hydrogen) is supplied to the nickel catalyst tube by a tee fitting between the oxidation and nickel catalyst tubes at a flow rate of approximately 45% of the total final flow.

e. Flame-Out Buffer

The flame out buffer consists of Haysep Q 80/100 mesh packed in a 6 ft. length of 1/8 in. diameter stainless steel tubing. The flame out buffer is maintained at the FID detector temperature of 220 ± 5 °C.

f. FID

An FID with a linear response ($\pm$ 5 percent) over the operating range of 0.5 to 50 ppm CH_4 is acceptable.

g. Data Recording System

Digital integration system compatible with the FID is used for permanently recording the analytical results. The system must have a software program capable of point to point baseline subtraction from the standard and sample runs.

h. Sample flow valves

Three multi-port valves are needed to accomplish the sample, carrier, and purge gas flow paths in this method. As specified in sections 4.8.1a, 4.8.1b, and 4.8.1c, a six port valve is used in the sample injection system, a four port valve is used to control flow through the separation columns, and a four port valve is needed for regeneration of the oxidation catalyst. Figure 25.3-7 depicts the configuration of these four valves and the position during each of two modes for each valve.

i. Syringes

Gas tight syringes, 30 ml and 100 ml capacities.

j. Reagents

1. Chromatographic grade helium as carrier gas.
2. Reagent grade hydrogen for reduction of CO_2 and FID fuel.
3. USP breathing grade hydrogen-free air for FID combustion.
4. Three point NIST traceable CO calibration standards

5. Three point NIST traceable CO_2 calibration standards
6. NIST traceable 1 ppm, 3 ppm, 10 ppm, and 100 ppm CH_4 standards in pure nitrogen
7. NIST traceable 1 ppm, 3 ppm, 10 ppm, and 100 ppm C_2H_4 standards in pure nitrogen
8. NIST traceable 1 ppm, 3 ppm, 10 ppm, and 100 ppm iso-butane standards for backflush in pure nitrogen
9. A high purity CO_2 (approximately 12% to 15% in pure hydrogen free nitrogen) is required as a background determination for high CO_2 sample.
10. Other standards as required

Note: Alternatively multi-component gases can be used for each concentration.

4.8.2 Other Apparatus and Reagents for TCA Analysis

Optionally the entire TCA system may be automated to control the temperatures, valving, and detector attenuation using a computer and control software. This system may feature analog/digital interface and a computer or an integrator for the data handling system.

4.9 TCA Analysis on the Canisters

4.9.1 Instrument Parameters and Gas Flow Rates

Set instrument parameters as follows:

Sample Injection Port/Loop : $150 \pm 5\ ^{o}C$

Detector : $220 \pm 5\ ^{o}C$

Oxidation catalyst : $650 \pm 5\ ^{o}C$

Reduction catalyst	: 380 ± 5 °C
Heated transfer lines	: 105 ± 5 °C
Sample flow valves	: inside separation column oven
Separation Column Oven	
Initial	: 50 ± 2 °C for 8 minutes starting at injection
Ramp	: Increase at a rate of 50 °C/min for 2 minutes
Final	: 150 ± 5 °C for 5 minutes
Column Bake-Out	: 190 ± 5 °C for 2 minutes

Gas flow rates:

Helium Carrier	: 30 ml/min
Oxidation Catalyst Regeneration Air	: 100 ml/min
Oxidation Catalyst Air	: 180 ml/min
Methanizer Hydrogen	: 12.3 ml/min
FID Hydrogen	: 30 ml/min
FID Air	: 300 ml/min

4.9.2 Equipment Conditioning

a) Establish all initial temperatures and gas flow rates as specified above.

b) Switch the valving so that the GC carrier stream is routed through the oxidation catalyst system (Valves 1 and 2 of Figure 25.5-7 in Position 1) for 5 minutes.

c) Switch the valving so that the GC carrier stream is routed through both the oxidation catalyst and the reduction catalyst system (Valve 3 of Figure 25.5-7 in Position 1).

d) Turn on the detector air and hydrogen gases, then ignite the detector. The detector attenuation is set at 8 and the range at 12.

e) Flush the 30 ml size sample syringe five times with ultra pure nitrogen.

f) Flush ultra pure nitrogen gas through the sampling connector fitting for 30 seconds for cleaning purposes.

g) Clean the injection system by flushing at least three syringe volumes of ultra pure nitrogen gas.

4.9.3 TCA Procedure

Reproduce exactly the timing of valve switching and column temperature changes for each blank, sample, and standard runs in a series. The following is the sequence of events that occur during a single injection of standard, baseline, or sample; the required sequence in which standards blanks and samples are injected is given in Section 4.9.4. Refer to Figure 25.3-7 for references to the valve and position numbers as indicated in parentheses and to Figure 25.3-8 for a summary of the equipment operation.

a) Verify that the column temperature is 50 ± 2 °C and that the sample loop valve is switched so that the carrier gas is routed through the column (valve 1 in position 1). Also verify that the column valve is switched so that the carrier flows in the forward direction (valve 2 on position 1) and that the oxidizer valve is switched so that the carrier is routed through the oxidizer (valve 3 in position 1)

b) Inject at least 25 ml of sample with the 30 ml size syringe.

c) Immediately after completing the sample injection, switch the sample loop valve so that the carrier flows in the forward direction so that the sample loop is swept through the column (valve 1 in position 2)

d) Observe the chromatogram and allow the CO_2, CH_4, ethylene (if present), and ethane to be eluted from the column. An example chromatogram is shown in Figure 25.3-9. The period of time during which this takes place should be approximately eight minutes.

e) After ethane elutes, switch the column valve to backflush mode so that the carrier flow reverses direction through the column and elutes organics as a back-flush peak (valve 2 in position 2).

f) Immediately upon switching to backflush mode heat the column oven using a pre-set temperature profile so that the backflush elutes at a rate so that the detector responds in its analytical detection range. The temperature profile should be approximately a follows: Ramp: Increase at a rate of 50 °C/min for 2 minutes, Final: 150 ± 5 °C for 5 minutes.

In all of the steps, the valving is such that the effluent from the column is directed to the oxidation reduction and FID detector system. Detector output for the back-flush peak is sent to the integrator where a response vs. time curve is plotted and the area under the back-flush peak is integrated. The switching can be accomplished by manual or automated valving.

Since NMNEOC is a mixture, this back-flush peak may not be symmetrical; however, the area under a response vs. time curve is proportional to the amount of carbon present in the sample.

For high CO_2 (3% to 15%) and low back-flush (backflush from <1 to 10 ppm) samples, adjust run time to allow the detector signal to return to the baseline before the back-flush peak elutes. Measure the CO_2 content separately by an instrument capable of measuring % levels CO_2 such as SCAQMD Method 10.1.

4.9.4 Order of Standard, Background, and Sample Injections

Several standards and backgrounds are run with a batch of samples because of the difficulty in measuring low level concentrations. The following is the order in which the standards and backgrounds must be run in relation to the samples. Each step is run through the full fore-flush and backflush of the procedure as previously described in Section 4.9.3.

a) Inject laboratory air to condition the system and serve as system check by comparing to historical injections. The system should be able to detect the background level of 2 - 10 ppm and be consistent with historical levels, otherwise repeat the laboratory air injection.

b) Inject CO_2 free N_2 gas to determine "background nitrogen" for NMNEOC peak (back-flush). The area counts of the back-flush should be within a historical acceptable area, otherwise repeat the background nitrogen injection. Save the background nitrogen chromatogram for background subtraction on the subsequent runs.

c) Inject three level concentrations of TCA standards (recommended: 3, 10 and 100 ppmv) to create a 3-point calibration curve. Accept the calibration curve if the measured concentrations are within 10% of the check standards. Otherwise repeat.

d) After calibration, again inject the background nitrogen.

e) Inject a 1 ppmv back flush standard. The measured back-flush concentration must be within ± 20% of the standard, otherwise repeat the background nitrogen and the 1 ppm backflush standard.

f) Inject the samples in duplicate (each sample is analyzed two times as in Section 4.9.3). Analyze low concentration samples before high concentration samples. No more than eight injections (four duplicates) may be performed in a single batch. Inject the nitrogen background between batches and at the end of the sample injections.

g) Run two QC standards, choose concentration levels that bracket the sample concentrations if possible. If the sample has back-flush concentration close to 1 ppmv, use 1 ppmv as the lower of the QC standards. The measured back-flush concentration should be within ± 20% of the standard, otherwise select a new background nitrogen for baseline subtraction as follows: Select the new background nitrogen chromatogram by injecting nitrogen followed by the 1 ppmv back flush standard. When the results of the 1 ppm back-flush standard are within the ± 20% criteria, the chromatogram for the nitrogen can be used for baseline subtraction. If necessary, divide a large batch of samples runs in the same day into small batches, and use different background nitrogen for baseline subtraction as long as the 1 ppmv back flush standard before and after that particular batch meet the ± 20% criteria.

In standby mode, the column temperature is set to 190 ± 5 °C. The valving is set so that air is allowed to flow through the oxidation catalyst in the backflush mode overnight (valve 1 position 2, valve 2 position 2, valve 3 position 2). This step is essential for the oxidation catalyst to be at full capacity for the next use.

The instrument must not be used unless the oxidation catalyst has been regenerated in this manner.

4.10 TCA Analysis Quality Assurance (QA) Criteria

Pre and post run QC concentrations must be within 10% the standard concentrations. The following are the required agreement between duplicate analyses of a sample:

Back-flush concentration (ppmv)	% difference from mean
1-3	20
4-6	15
7-12	12
13-30	10
31-50	5

If the duplicate analyses do not fall within the required limit, run a third analysis. If after the third analysis, the mean does not meet the above requirements, review the instrument calibration and the baseline nitrogen for errors, make necessary changes, then restart from the background nitrogen step (Step d).

4.11 TCA Calculations

Calculate the concentration of component in the canister using the following equation :

$$C_c = C_m \times DF \times (P_f/P_r)$$

where

C_c = end of sampling canister concentration, ppmv

C_m = average of duplicate measured concentrations from TCA analysis, ppmv

DF = syringe dilution factor if applicable

P_f = canister pressure after pressurization, mm Hg

P_r = before purging canister pressure, mm Hg

Calculate the total VOC as equivalent to gaseous carbon using the following equation:

$$\text{Total VOC (ppmC)} = C_w + C_c$$

where

C_w = VOC from condensate trap water (ppmC)

C_c = VOC from canister(ppmv)

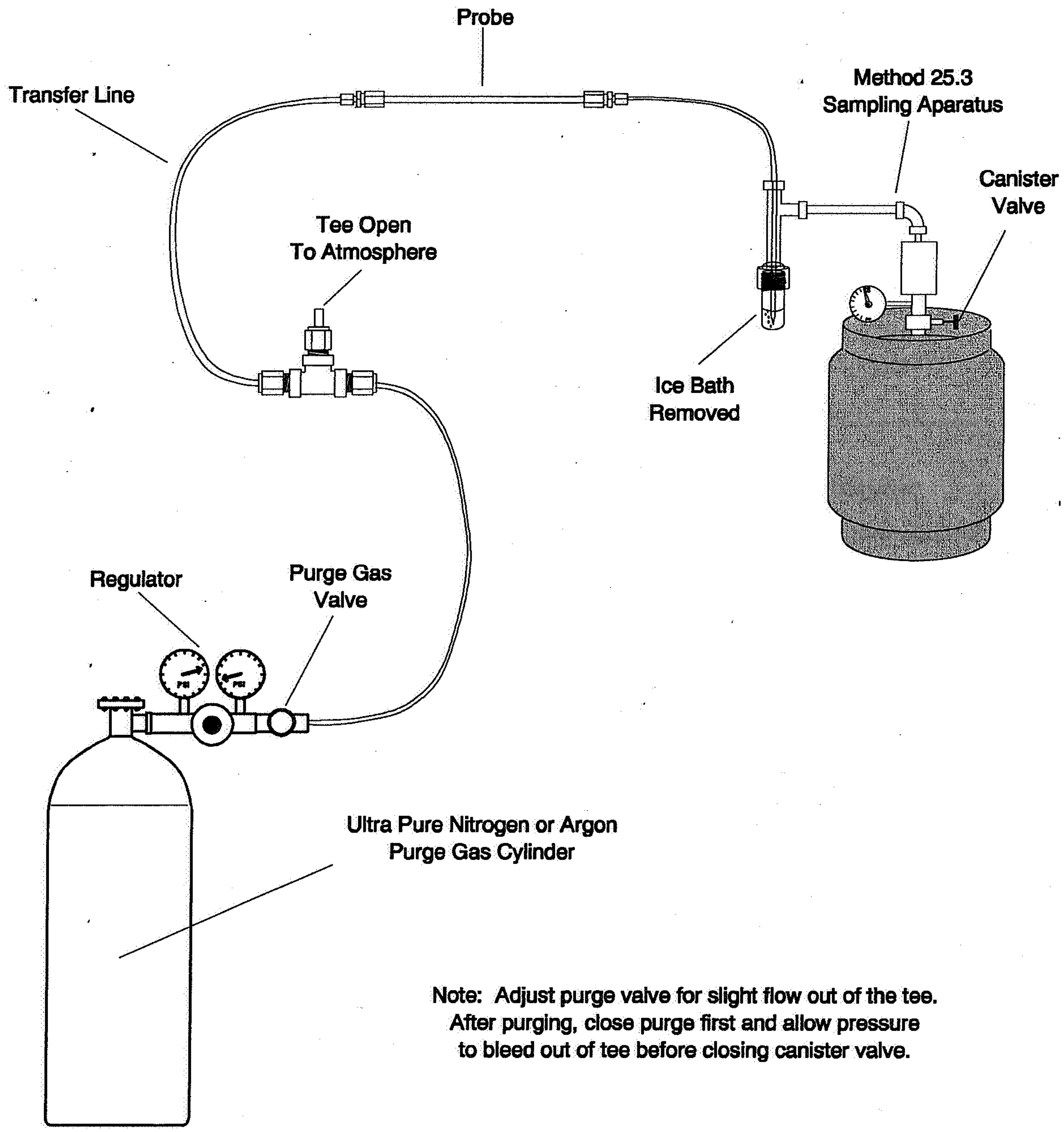

Figure 25.3-5 Inert Gas Purging

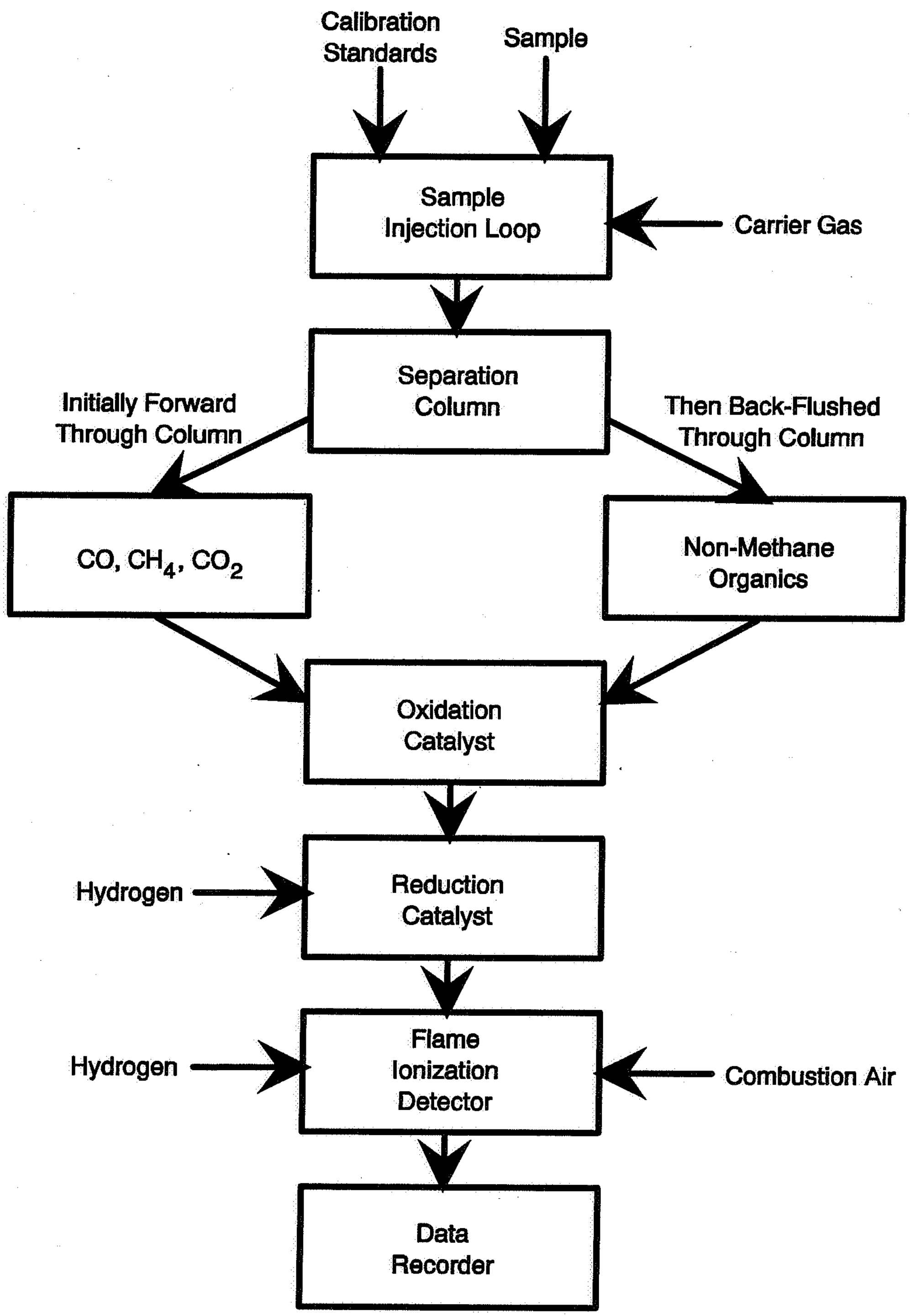

Figure 25.3-6 Flow Diagram for TCA Analysis on Canisters

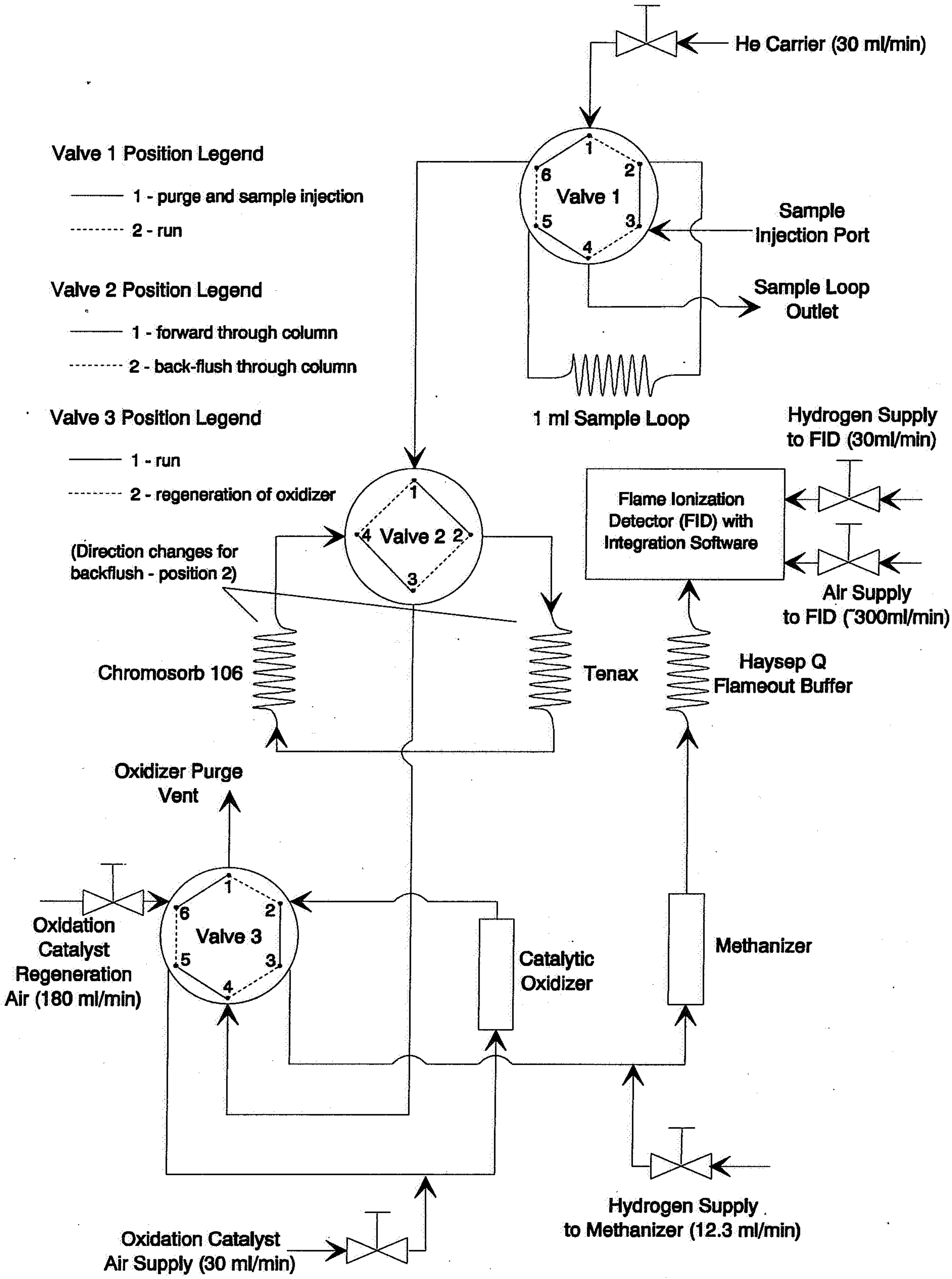

Figure 25.3-7 Equipment Diagram for TCA Analysis on Canisters

Equipment Operation for TCA Analysis on Canisters

Step #	Time	Valve 1 Position	Valve 2 Position	Valve 3 Position	Description
1	0	1	1	1	Verify Temperatures and Valve Positions
2	0	1	1	1	Inject Sample
3	after inj.	2	1	1	Switch Carrier Flow Through Sample Loop
4	0-8 min.	2	1	1	Observe CO_2, CH_4, Ethane Elute
5	8 min	2	2	1	Switch to Backflush Mode
6	8-15 min	2	2	1	Increase Column Oven Temp by 50°C/min for 2 min, Hold at 150 °C for 5 min
7	Over-night	2	2	2	Increase Column Oven Temp to 190 °C to Regenerate Oxidation Catalyst

Figure 25.3-8 Equipment Operation for TCA Analysis on Canisters

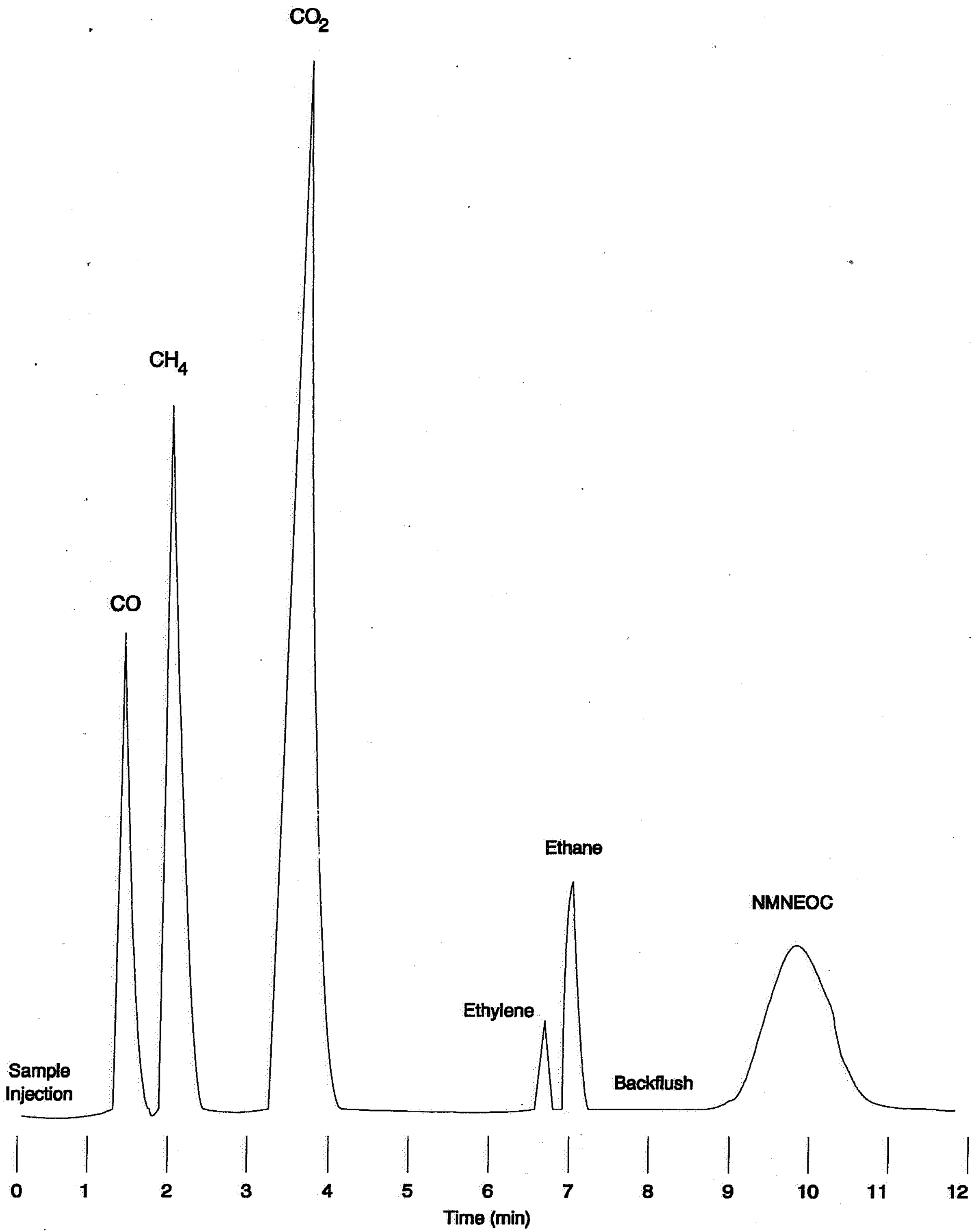

Figure 25.3-9 Example Chromatogram for TCA Analysis on Canisters

METHOD 25.3

DETERMINATION OF LOW CONCENTRATION NON-METHANE NON-ETHANE ORGANIC COMPOUND EMISSIONS FROM CLEAN FUELED COMBUSTION SOURCES

Section 5 of 5

5. Engineering Calculations and Reporting

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation.

5.1 Data Quality Checks

The results of the duplicate sampling for NMNEOC must not deviate more than 20% from the average of the two values in order to meet the precision criteria. The results of the duplicate sampling for carbon monoxide and carbon dioxide must not deviate more than 20% from the average of the two values in order to meet the leak indicator criteria. Field observations of occurrences that may cause sample bias may be used to invalidate one of the duplicate samples in the case that the 20% precision criteria is not satisfied. Individual results cannot, however, be discarded solely on the basis that the results disagree or that the results are higher than anticipated. Contamination cannot be used to invalidate the sample without substantial evidence that contamination occurred. Alternatively the lower value can be discarded for a worst case evaluation.

5.2 VOC Molecular Weight per Carbon Ratio

In order to convert the lab results as carbon to actual mass emissions as VOC. A molecular weight per carbon ratio must be either measured, calculated or assumed. Although a qualitative analytical speciation of the VOC using an approved method is preferable, it is sometimes not easily accomplished, and other times not feasible due to partitioning of the sample into gaseous and condensable fractions. Other times the ratio can be calculated based on the VOC formulation of materials consumed in, for example, a coating or printing operation. In these situations, it is acceptable to use information provided in Material Data Safety Sheets (MSDS), if considered accurate. The use of MSDS information is generally, however, not considered as sufficiently accurate for calculating capture efficiencies. It is acceptable for calculating destruction efficiencies since the molecular weight per carbon ratio cancels out of the calculation when it is assumed that the ratio remains constant across the control device. In many cases the ratio can be considered as represented by a surrogate compound that is representative of the VOC encountered in the process. In the absence of any of the aforementioned information, common practice has dictated the use of a default ratio of hexane which is 14.36 lb/lb-mol C. Table 25.3-2 lists several general categories of molecular weight per carbon ratios which have been deemed as acceptable for the specified applications. Several specific examples are given below:

a. For Coating and Printing Processes:

Most Preferred: Volatile Carbon Analysis from SCAQMD Protocol for Determination of VOC Capture Efficiency

Calculation: 12 lb/lb mol x % VOC weighted average / % volatile carbon weighted average (all percents by weight)

Example: Coating #1 VOC = 50%, % volatile carbon = 40%, usage = 100 lb/hr

Coating #2 VOC = 80%, % volatile carbon = 60%, usage = 10 lb/hr

$$MW/C = \frac{12 \text{ lb/lb-mol} \times [(50\% \times 100 \text{ lb/hr}) + (80\% \times 10 \text{ lb/hr})]}{[(40\% \times 100 \text{ lb/hr}) + (60\% \times 10 \text{ lb/hr})]}$$

$$= 15.13 \text{ lb/lb-molC}$$

b. For Coating and Printing Processes: 2nd Choice- MSDS or Formulation Information

MSDS formulation is usually given as weight percent of the total coating/solvent

Calculation: $MW/C = \Sigma(MW \times \text{mol frac}) / \Sigma(\text{carbon\#} \times \text{mol frac})$

Example: Coating #1 VOC formulation = 10% benzene, 20% formaldehyde

usage = 10 lb/hr

Coating #2 VOC formulation = 30% butanol, 40% ethylene glycol monoethyl ether (a.k.a. EGMEE, Cellosolve; 2-Ethoxyethanol),

usage = 100 lb/hr

Benzene Usage = (10% x 10 lb/hr) / 100 = 1 lb/hr

Formaldehyde Usage = (20% x 10 lb/hr) / 100 = 2 lb/hr

Butanol Usage = (30% x 100 lb/hr) / 100 = 30 lb/hr

EGMEE Usage = (40% x 100 lb/hr) / 100 = 40 lb/hr

$MW_{benzene} = 78$ lb/lb-mol, $C\#_{benzene} = 6$

$MW_{formaldehyde} = 30$ lb/lb-mol, $C\#_{formaldehyde} = 1$

$MW_{butanol} = 74$ lb/lb-mol, $C\#_{butanol} = 4$

$MW_{EGMEE} = 90$ lb/lb-mol, $C\#_{EGMEE} = 4$

$\text{mol frac}_i = (\text{usage}_i / MW_i) / \Sigma(\text{usage}_i / MW_i)$

$$\begin{aligned}\Sigma(\text{usage}_i / MW_i) = {} & (1\ \text{lb/hr}_{benzene} / 78\ \text{lb/lb-mol}_{benzene}) \\ & + (2\ \text{lb/hr}_{formaldehyde} / 30\ \text{lb/lb-mol}_{formaldehyde}) \\ & + (30\ \text{lb/hr}_{butanol} / 74\ \text{lb/lb-mol}_{butanol}) \\ & + (40\ \text{lb/hr}_{EGMEE} / 90\ \text{lb/lb-mol}_{EGMEE}) \\ & = 0.929\ \text{lb-mol}_{VOC}/\text{hr}\end{aligned}$$

$\text{mol frac}_{benzene} = (1\ \text{lb/hr}_{benzene} / 78\ \text{lb/lb-mol}_{benzene}) / 0.929 = 0.014$

$\text{mol frac}_{form} = (2\ \text{lb/hr}_{form} / 30\ \text{lb/lb-mol}_{form}) / 0.929 = 0.072$

$\text{mol frac}_{butanol} = (30\ \text{lb/hr}_{butanol} / 74\ \text{lb/lb-mol}_{butanol}) / 0.929 = 0.436$

$\text{mol frac}_{EGMEE} = (40\ \text{lb/hr}_{EGMEE} / 90\ \text{lb/lb-mol}_{EGMEE}) / 0.929 = 0.478$

$$MW/C = \frac{(78\ \text{lb/lb-mol} \times 0.014) + (30\ \text{lb/lb-mol} \times 0.072) + (74\ \text{lb/lb-mol} \times 0.436) + (90\ \text{lb/lb-mol} \times 0.478)}{(6\ C \times 0.014) + (1\ C \times 0.072) + (4\ C \times 0.436) + (4\ C \times 0.478)}$$

MW/C = 20.6 lb/lb-molC

c. If the permit or other emissions limit is specified as a specific compound:

Calculation: MW/C# of specified compound

Example: Permit limit is specified as emissions in units of VOC as Hexane

MW = 86.17 lb/lb-mol

C# = 6.000

MW/C = 86.17 lb/lb-mol / 6.000 C

MW/C = 14.36 lb/lb-mol

d. For Combustion of Only Natural Gas Only:

Calculation: MW/C# of Methane or Hexane. Methane is preferable when either a worst case emission rate is desired or formaldehyde by-products may be present due to incomplete combustion. Incomplete combustion may be indicated by unusually high levels of methane or carbon monoxide.

Example: as Methane.

MW = 16.04 lb/lb-mol

C# = 1.000

MW/C = 16.04 lb/lb-mol / 1.000 C

MW/C = 16.04 lb/lb-mol

e. For fugitive emissions from petroleum processing operations:

Calculation: MW/C# of propane or other compounds if known

Example: as propane

MW = 44.10 lb/lb-mol

C# = 3.000

MW/C = 44.10 lb/lb-mol / 3.000 C

MW/C = 14.70 lb/lb-mol

e. For processes that use strictly petroleum distillates:

Calculation: ((14 x C#) +2) / C#

Example: for an average carbon number of 8.

MW/C = ((14 x 8) +2) / 8

MW/C = 14.3 lb/lb-mol

In absence of any information regarding the composition of the VOC, generally the molecular weight per carbon ratio of hexane is assumed (14.36 lb/lb-molC). As for the general range of molecular weight to carbon ratios for most VOC mixtures encountered, formaldehyde (30.03 lb/lb-molC) and methanol (32.04 lb/lb-molC) represent the upper bounds, while benzene represents the lower bound (13.02 lb/lb-molC). In applications where the molecular weight per carbon ratio is either difficult to determine as above or in dispute, a worst case scenario can be used for compliance purposes .

5.3 Bias Correction Factor

During the USEPA's Office of Air Quality Planning and Standards (OAQPS) evaluation of this source test method, it was determined that a bias correction factor must be applied to all results achieved by this method. This correction factor of 1.086 was determined according to USEPA Method 301 for validating test methods and was based on the results of the validation testing. The calculation is performed as follows:

Corrected Conc. (ppmC) = Total VOC (ppmC as determined in Section 4.11) x 1.086

5.4 VOC Mass Emission Rate Calculation

The individual VOC mass emission rates are determined using the following quantities for each duct or stack where both a concentration and corresponding flow rate are determined:

C - Average Corrected Concentration of Non-Methane Non-Ethane Organic Compounds (NMNEOC) from the Method 25.3 sampling pairs reported in ppmC;

Q - Volumetric flow rate as determined by SCAQMD Methods 1.1 through 4.1 in dry standard cubic feet per minute;

MW - Molecular Weight per Carbon Ratio as determined in Section 5.2 in lb/lb-mol C;

The VOC mass emissions rate in pounds per hour can then be calculated as follows:

VOC Mass Emission Rate (lb/hr) = $1.583 \times 10^{-7} \times MW \times C \times Q$

These calculations can be performed by using the calculation sheet in Figure 1. If multiple emission points are present, the VOC mass emission rate must be calculated separately as above and added together for a total VOC mass emission rate.

Application	Method	Calculation	MW/C Ratio	Typical Range
Coating and Printing Operations	% Volatile Carbon Analysis from SCAQMD Protocol for Determination of VOC Capture Efficiency	12 lb/lb mol x % VOC weighted average / % volatile carbon weighted average	Varies	13-32 lb/lb-mol C
Coating and Printing Operations	MSDS Information	Σ(MW x mol frac)/ Σ(carbon# x mol frac)	Varies	13-32 lb/lb-mol C
When Permit Specifies Compound to be Reported as:	Specified Compound	MW/C#	Varies	13-32 lb/lb-mol C
Natural Gas/Fuel Gas Combustion	Assume Hexane	MW/C#	14.36 lb/lb-mol C	14.36 lb/lb-mol C
Natural Gas/Fuel Gas Combustion for Worst Case or Incomplete Combustion	Assume Methane (although non-VOC, sometimes used, accounts for formaldehyde formation)	MW/C#	16.04 lb/lb-mol C	16.04 lb/lb-mol C
Fugitive Emissions from Petroleum Processing Operations	Assume Propane	MW/C#	14.70 lb/lb-mol C	14.70 lb/lb-mol C
Ethanol Only Processes (ethanol combustion, investment casting, flexographic processes)	Assume Ethanol	MW/C#	23.03 lb/lb-mol C	23.03 lb/lb-mol C
Processes That Use Strictly Petroleum Distillates	Average Carbon Number	$\frac{(14 \times C\#) + 2}{C\#}$	Varies	14-15 lb/lb-mol C
Processes where the Formulation of the VOC is Known	VOC Formulation	Σ(MW x mol frac)/ Σ(carbon# x mol frac)	Varies	13-32 lb/lb-mol C
In Absence of Information for Applying Any of the Above	Assume Hexane	MW/C#	14.36 lb/lb-mol C	14.36 lb/lb-mol C

Figure 25.3-10 Molecular Weight per Carbon Ratios

Test No.______ Date____________

SOURCE TEST CALCULATIONS

Duct Identification	Flow Rate (dscfm)	NMNEOC Conc. (ppm)	VOC Mass Rate (lb/hr)
#1			
#2			
#3			
#4			
TOTAL		N/A	

WHERE:

VOC Mass Rate =

1.583×10^{-7} x (Flow Rate dscfm) x (NMNEOC ppm) (MW per Carbon Ratio lb/lb-mol C)

FIGURE 25.3-11
VOC MASS EMISSION RATE CALCULATION

Appendix D

Waste Gas Source Test Data

Waste Gas Source Test Data

	NOx	CO	VOC*
	lb/MW-hr		
Proposed 2008 Standard	0.5	6.0	1.0
Porposed 2013 Standard	0.07	0.10	0.02

Landfill gas fueled	lb/MW-hr		
Microturbines	NOx	CO	VOC*
1	0.20	0.50	0.09
2	0.20	0.10	0.16
3	0.16	0.17	0.19
4	0.14	0.46	0.16
5	0.12	0.37	0.19
6	0.12	0.36	0.14
7	0.09	0.40	0.19
8	0.06	0.06	0.13
Fuel Cells			
1	0.01	0.02	NA
averages	**0.12**	**0.27**	**0.16**

Digester gas fueled	lb/MW-hr		
Microturbines	NOx	CO	VOC*
1	0.19	0.13	0.22
2	0.15	3.17	0.12
3	0.08	9.00	0.45
4	0.07	4.67	0.15
Fuel Cells			
1	0.01	0.03	0.70
averages	**0.10**	**3.40**	**0.33**

Oil field waste gas fueled	lb/MW-hr		
Mircoturbines	NOx	CO	VOC*
1	0.20	0.19	0.20
averages	**0.20**	**0.19**	**0.20**

*VOCs listed as hexane