ATTACHMENT F

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Revised Draft Staff Report
Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

August 2012

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The South Coast Air Quality Management District (AQMD) is the air pollution control agency for all of Orange County and the urban portions of Los Angeles, Riverside and San Bernardino counties. AQMD is responsible for controlling emissions primarily from non-vehicular sources of air pollution.

Rule 1110.2 regulates oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compound (VOC) emissions from liquid and gas fueled internal combustion engines operating in the AQMD producing more than 50 rated brake horsepower (bhp). The rule was adopted in 1990 and last amended in 2010 to add an exemption affecting a remote public safety communications site.

The amendment in 2008 set concentration limits for landfill and digester gas-fired engines to become effective on July 1, 2012, subject to a Technology Assessment. The biogas emission standards adopted in 2008, except for CO, were equivalent to the current Best Available Control Technology (BACT) standard. Biogas engines regulated by this rule include approximately 55 engines operated by 13 public and private operators of landfills and wastewater treatment plants. The rule and the adopting resolutions directed staff to conduct and complete a Technology Assessment before July 2010 to confirm the achievability of the July 1, 2012 compliance limits for biogas engines. If the Technology Assessment could not confirm the 2012 limits' achievability, the 2012 limits would not be treated as effective.

District staff presented an Interim Report on the Technology Assessment for Rule 1110.2 Biogas Engines to the Governing Board in July 2010. The report pointed to two potential technologies that were a part of demonstration projects in the basin. However, the permit moratorium in 2009 caused a delay in the startup of these projects. One pilot study has since been successfully completed, but the other demonstration project's startup and completion has been affected by other unforeseen delays. The Interim Technology Assessment mentioned the possible necessity of an adjustment to the July 1, 2012 effective date to facilitate the completion of the technology assessment and implementation of the 2008 amendment.

The proposed amendments will:

- Re-establish the effectiveness of the previously adopted 2012 limits. Allow biogas engine operators ~~three to~~ ~~four~~ three and a half more years to comply with the 2012 emission limits. The new effective date will be January~~July~~ 1, 2016~~5~~ for all biogas engines.~~the first engine or a biogas cleanup system for the entire biogas engine fleet. The remaining engines will have an additional year to comply.~~
- Provide a compliance option with a longer averaging time to engine operators that can demonstrate through continuous emission monitoring systems (CEMS) data mass emission levels at least 10 percent lower than allowable under the rule's proposed concentration limits for NOx and CO. The feasibility of the lower mass

emissions was demonstrated by the recently completed pilot study by Orange County Sanitation District (OCSD), which indicated that lower NOx mass emissions can be achieved in conjunction with longer averaging times. This longer averaging time would be allowed provided that the CEMS data routinely shows emission levels below 11 ppm for NOx and below 250 ppm for CO.

- Provide an alternate compliance option to give operators under long term fixed price power purchase agreements entered into prior to the February 1, 2008 amendments and extending beyond the January 1, 2016 compliance date additional time (up to two years beyond the compliance date) to comply with the emission limits with the payment of a compliance flexibility fee.
- Biogas engines achieving early compliance (i.e. January 1, 2015) will have their permit application fees refunded.

The project will result in 0.9 tons per day of NOx reductions, 0.5 tons per day of VOC reductions, and 20 tons per day of CO reductions. The range of cost effectiveness using the District model is between $1,700 and $3,500 per ton of combined NOx, VOC, and CO reduced (NOx + VOC+ 1/7 CO). Cost effectiveness was calculated based on actual control costs for installations in the Basin and in the Bay Area. Staff also added costs for additional gas cleanup and a 20% capital cost contingency to arrive at an upper cost effectiveness range between $2,600 and $5,900 per ton. It should be noted that recently adopted AQMD NOx regulations ranged in cost effectiveness from $10,000 to $30,000 per ton.

District staff has met on several occasions with stakeholders and the affected community to discuss the feasibility of the required controls and their cost effectiveness. Staff has also met individually with nearly every affected facility operator to discuss site-specific issues. Information on Selective Catalytic Reduction (SCR)/catalytic oxidation-based after treatment technology from the two projects in this Basin and in the Bay Area to date provides ample evidence in support of the feasibility of the proposed limits and the completion of the Technology Assessment. However, on-going demonstration projects with alternate technologies, if successful, could also provide our stakeholders with additional useful information and alternate compliance routes. Staff intends to continue the technology review efforts with stakeholders even after the completion of this rulemaking process.

CHAPTER 1: BACKGROUND

INTRODUCTION

REGULATORY HISTORY

SILOXANES IN BIOGAS

KEY ISSUES

AFFECTED INDUSTRIES

PUBLIC PROCESS

INTRODUCTION

The California Health and Safety Code requires the AQMD to adopt an Air Quality Management Plan (AQMP) to meet state and federal ambient air quality standards and adopt rules and regulations that carry out the objectives of the AQMP. The California Health and Safety Code also requires the AQMD to implement all feasible measures to reduce air pollution. The 2007 AQMP has found that additional reductions are needed to meet the more stringent federal ozone and particulate matter standards. Reductions in NOx will help in main~~at~~taining the federal 24-hour average $PM_{2.5}$ standard in 2014~~9~~, while reductions in NOx and VOC will aid in attaining the ozone standard in 2023. Figure 1 shows the projected baseline emissions for NOx and VOC and the required emissions to achieve the ozone standard in 2023. Further NOx and VOC reductions from Rule 1110.2 biogas engines are essential for achieving compliance with federal and state ambient air quality standards for PM2.5 and ozone.

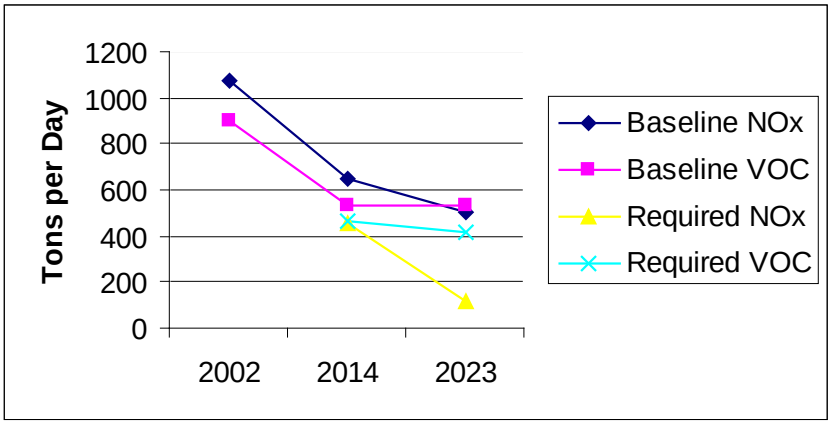

Figure 1. NOx and VOC Baseline Emissions and Emissions Needed to Achieve the 2023 Ozone Standard

Engines that are fueled by biogas (landfill or digester gas) make up about 7% of stationary, non-emergency engines in the AQMD. Of all the combustion sources, these engines inherently have the highest emissions. Rule 1110.2, "Emissions from Gaseous- and Liquid-Fueled Engines," was first adopted in 1990 to address emissions from stationary engines in this category. Since the first adoption of the rule, advances in low NOx burner and post combustion control technology have been demonstrated and implemented on several categories of combustion equipment. In contrast, the current NOx concentration BACT and rule limits for biogas engines are at least twelve times higher than allowed by AQMD boiler rules.

Projected NOx emissions reductions from biogas engines achieving the emissions limits set in the 2008 rule amendment were not included in the State Implementation Plan (SIP)

during the 2008 amendment because they were contingent on the completion of a Technology Assessment. However, sufficient information currently exists for the completion of the Final Technology Assessment to support the current amendment of this rule. As a result, the NOx reductions from biogas engines will be incorporated into the SIP to further promote the District's efforts towards the attainment of federal and state $PM_{2.5}$ and ozone air quality standards.

REGULATORY HISTORY

Rule 1110.2 – Emissions from Gaseous- and Liquid-Fired Engines was adopted by the AQMD Governing Board on August 3, 1990. It required that either 1) NOx emissions be reduced over 90% to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language and then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted non-road engines, including portable engines, from most requirements. The amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

To address widespread non-compliance with stationary IC engines, the 2008 amendment augmented the source testing, continuous monitoring, inspection and maintenance (I&M), and reporting requirements of the rule to improve compliance. It also required stationary, non-emergency engines to meet emission standards equivalent to current BACT for NOx and VOC and almost to BACT for CO. This partially implemented the 2007 AQMP control measure for Facility Modernization (MCS-001). Additionally, the 2008 amendment required new electric generating engines to limit emissions to levels nearly equivalent to large central power plants, meeting standards that are at or near the CARB 2007 Distributed Generation Emissions Standards. It also clarified the status for portable engines and set emissions standards for biogas engines to become effective on July 1, 2012 if the July 2010 Technology Assessment would confirm the achievability of those limits.

The 2008 adopting resolution included commitments directing staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Additionally, the Governing Board directed that the July 2012 biogas emission limits will not be incorporated into the SIP unless the July 2010 Technology Assessment finds that the proposed limits are achievable and cost-effective.

The most recent amendment in July 2010 added an exemption to the rule affecting a remote public safety communications site at Santa Rosa Peak in Riverside County which has limited accessibility in the wintertime.

At the July 2010 Governing Board meeting, staff presented an Interim Technology Assessment to address the board resolution commitments in 2008. The Interim Technology Assessment summarized the biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of a subsequent report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology should be available that can support the feasibility of the July 2012 emission limits, but that the delay in the demonstration projects will likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

SILOXANES IN BIOGAS

Siloxanes are a type of organosilicon compound that exists in many cosmetic, personal and household products. When disposed, these compounds can end up either at wastewater (sewage) treatment plants or in landfills. It is a well known fact that impurities in the biogas affect engine performance. Once oxidized into silicon dioxide (SiO_2) upon combustion, glass-like siloxane deposits can form on moving engine parts such as valves and pistons. Siloxanes in the biogas are responsible for increased engine maintenance, and have the potential to cause significant damage to internal engine components if not removed either before combustion or during routine maintenance service. Additionally, siloxanes, if untreated and combusted, can foul catalyst-based post-combustion controls and make them much less effective in their pollutant removal potential. Siloxanes that make it out through the engine exhaust stream can deposit themselves on the downstream catalyst's available active sites and thereby reduce the pollutant removal efficiency.

In the Interim Technology Assessment, siloxane data was obtained from the Southern California Association of Public Treatment Works (SCAP) and showed that there is variability in the siloxane levels at different locations for digester plants and landfills (Table 1).

Table 1. SCAP Data Showing Siloxane Concentrations in Biogas

Site	Type of Biogas	Average Siloxane Concentration (ppmv)
Palmdale	Digester	0.9
San Bernardino	Digester	0.9
Fountain Valley	Digester	2.59
Huntington Beach	Digester	2.25
Lancaster	Digester	3.9
RP-1	Digester	5.15
JWPCP	Digester	5.31
Hyperion	Digester	8.51
Calabasas	Landfill	0.34
Spadra	Landfill	0.51
Puente Hills	Landfill	3.3

From the data obtained in the Interim Report, the time average siloxane concentration ranges for digester and landfill gas are as follows:

Digester Gas: 0.26 – 9.7 ppmv

Landfill Gas: 0.1 – 3.3 ppmv

During discussions with stakeholders, some have reported levels below 10 ppmv, while others have reported siloxane levels of above 100 ppmv. Regardless of the inlet siloxane level of the biogas, a treatment system capable of handling the baseline level and spikes is absolutely critical to preserve engine and catalyst control system performance.

KEY ISSUES

From ongoing meetings with the affected stakeholders in the Biogas Technology Advisory Committee, staff has summarized key issues that have resulted from those discussions.

1. *Cost of Biogas Cleanup*. The capital and operating costs for cleaning up the biogas are very high, especially for those applications that have variable and elevated siloxane levels.
2. *Space Requirements*. Some facility owners and operators may have to build ancillary structures, such as elevated platforms, to accommodate the control equipment which increases the installation costs. This is due to specific site constraints with existing equipment and structures.

3. *Cost of Exhaust Gas Cleanup*. Post-combustion control technologies such as Catalytic Oxidation and Selective Catalytic Reduction (SCR) are expensive to install and operate.
4. *Contracted Facilities*. Some facility operators only lease the gas supplied by a landfill and combust the gas for power production. These entities allege that they are bound by power purchase agreements that may prevent them from installing control equipment to reduce emissions within the next few years.
5. *Life of Landfill Operations/Equipment*. The volume and quality of landfill gas decreases once the landfill ceases to accept municipal solid waste. Some facilities have expressed concerns that by the time the proposed limits become effective, the gas quality will not be sufficient to utilize an engine. These operators feel that they should not retrofit equipment that will be placed out of service within a short time frame.
6. *Selling Gas to Pipeline*. Although it is not currently allowed in the state of California, producing pipeline-quality gas from landfill gas can be a possibility in the future through changes in state regulations (If this is the case, then there will be no utilization of engines and will consist of extensive gas cleanup only).
7. *Flaring as an Option*. Stakeholders have said that if the control technologies are too expensive, they will be left with no viable alternative but to shut down the engines and flare the biogas.

Responses to these comments are presented in Attachment B.

AFFECTED INDUSTRIES

Rule 1110.2 applies to stationary and portable reciprocating internal combustion engines (ICEs) over 50 brake horsepower (bhp). PAR 1110.2 affects the subset that contains engines fueled with biogas, which are those that are operated by landfills and wastewater treatment plants. Biogas engines are lean-burn engines that operate similarly to lean-burn natural gas-fired engines with a higher level of exhaust oxygen.

Landfills produce gas that results from the breakdown of municipal solid waste. This gas is primarily composed of methane and carbon dioxide. The gas is collected in a series of wells that transports it via pipeline to the landfill gas fired engines. The collected landfill gas fires one or more biogas engines with or without supplementation of natural gas.

Wastewater treatment plants produce digester gas from the plant's digesters. A digester uses heat and bacteria in an oxygen-free (anaerobic) environment to break down sewage sludge. A by-product of this process is biogas that contains methane. This biogas also fires one or more biogas engines with or without supplementation of natural gas. An advantage with using ICEs at wastewater treatment plants is that these are combined heat

and power (CHP) units. The waste heat created by the engine can be recovered and used to heat the plant's digesters, resulting in energy savings.

Whether coming from a landfill or an anaerobic digester, the biogas is used to fire an internal combustion engine with a generator to produce electricity. Some facilities are self-generating facilities that use the electricity to power their processes internally. Others sell off this generated power to the local utility grid. The wastewater treatment plants are primarily operated by public entities and utilities, while the landfills are operated by either public or private operators. There are a total of 8 public operators and 5 five private operators for biogas engines in the South Coast Basin.

There are 55 biogas engines operating in the Basin. Of these engines, 27 are digester gas-fueled and 28 are landfill gas-fueled. These engines are operated by 13 independent operators at 22 locations (6 operate digester gas-fueled engines and 7 operate landfill gas-fueled engines).

Despite past efforts to reduce emissions, biogas-fueled engines remain the dirtiest in terms of mass per unit power produced in the Basin, even though they are fired with renewable fuel. Even at BACT, these engines pollute significantly more than large central generating stations on a pound per megawatt-hour basis (Figure 2). For biogas ICEs, the NOx emissions are over 25 times higher than those of central power plants, 119 times higher for VOC, and 75 times higher for CO.

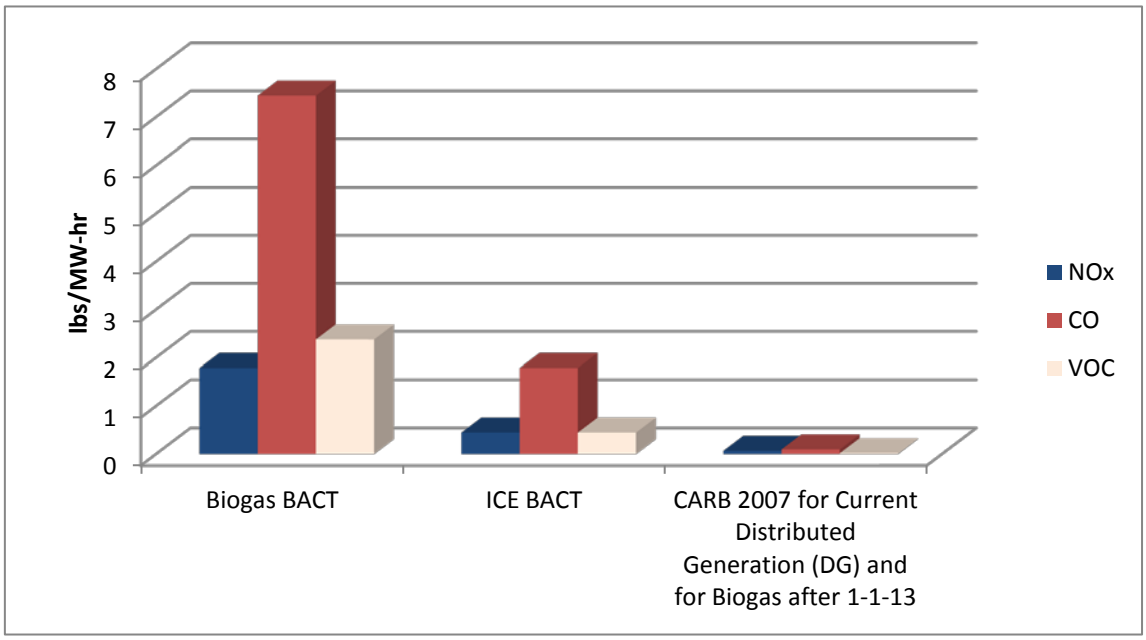

Figure 2. Current BACT for Biogas ICEs and Natural Gas ICEs vs. Central Generating Station BACT

During the 2010 Interim Technology Assessment, approximately 66 engines fueled by biogas were identified. Since that time, however, the number has decreased to 55 due to some engines being placed out of service. Nonetheless, the remaining biogas engines are among the top NOx emitters amongst stationary, non-emergency engines. Table 2 lists the top 25 NOx emitters based on annual reporting data for 2010. In this table, 13 of the 25 top NOx emitters in the basin are biogas-powered stationary, non-emergency engines. Forty-three percent of the NOx emissions in this table come from the 13 biogas engines. The remaining non-biogas facilities are now subject to the current Rule 1110.2 limits.

Table 2. "Top 25" Facilities with Highest NOx Emissions from Stationary, Non-Emergency Engines (Pounds per Year) in 2010

Facility	ID No.	NOx	ROG	CO	Fuel(s)
U.S. GOVT, DEPT OF NAVY	800263	110,713	8,967	24,390	Diesel
U.S. GOVT, DEPT OF NAVY	800263	80,714	9,701	26,387	Diesel
EXXONMOBIL OIL CORPORATION	800089	69,961	5,594	15,215	Diesel
LA COUNTY SANITATION DISTRICT-PUENTE HILLS	***25070***	***52,796***	***18,068***	***284,104***	***Landfill Gas***
ORANGE COUNTY SANITATION DISTRICT	***29110***	***48,912***	***68,945***	***611,663***	***Digester Gas***
ORANGE COUNTY SANITATION DISTRICT	***17301***	***41,478***	***43,767***	***426,682***	***Digester Gas***
U.S. GOVT, DEPT OF NAVY	800263	38,469	3,827	10,408	Diesel
CRIMSON RESOURCE MANAGEMENT	142517	38,093	507	64,119	Natural Gas (Rich-Burn)
MM LOPEZ ENERGY LLC	***104806***	***35,662***	***10,707***	***142,482***	***Landfill Gas***
MM PRIMA DESHECHA ENERGY, LLC	***117297***	***32,599***	***6,321***	***127,325***	***Landfill Gas***
MM PRIMA DESHECHA ENERGY, LLC	***117297***	***31,474***	***14,005***	***141,724***	***Landfill Gas***
EXXONMOBIL OIL CORPORATION	800089	28,192	2,254	6,131	Diesel
MM LOPEZ ENERGY LLC	***104806***	***28,189***	***11,753***	***110,606***	***Landfill Gas***
U.S. GOVT, DEPT OF NAVY	800263	21,923	2,181	5,931	Diesel
EOP - 10960 WILSHIRE LLC	119133	20,083	267	33,805	Natural Gas (Rich-Burn)
HOLLYWOOD PARK LAND COMPANY LLC	145829	19,792	1,583	4,304	Diesel
SAMUEL P LEWIS DBA CHINO WELDING & ASSEM	150351	19,542	260	32,894	Natural Gas (Rich-Burn)
TOYON LANDFILL GAS CONVERSION LLC	***142417***	***18,000***	***9,991***	***100,575***	***Landfill Gas***
ORANGE, COUNTY OF - SHERIFF DEPT, FAC OP	72525	17,314	499	1,344	Natural Gas (Lean-Burn)
BREA PARENT 2007, LLC	***113518***	***17,033***	***1,099***	***4,555***	***Landfill Gas***
HUNTINGTON BEACH CITY, WATER DEPT	20231	15,370	205	25,871	Natural Gas (Rich-Burn)
BREA PARENT 2007, LLC	***113518***	***15,346***	***784***	***3,140***	***Landfill Gas***
BREA PARENT 2007, LLC	***113518***	***14,181***	***1,052***	***4,958***	***Landfill Gas***
WASTE MGMT DISP & RECY SERVS INC (BRADLEY)	***50310***	***13,934***	***3,465***	***60,087***	***Landfill Gas***
WASTE MGMT DISP & RECY SERVS INC (BRADLEY)	***50310***	***13,839***	***3,823***	***67,514***	***Landfill Gas***
TOTALS, PPY		843,607	229,624	2,336,216	
TOTALS, TPY		421.8	114.8	1,168.1	
TOTALS, TPD		1.16	0.31	3.20	

PUBLIC PROCESS

Since the 2008 amendment, staff has held eight Biogas Technology Advisory Committee Meetings with representatives from affected facilities, manufacturers, consultants and other interested parties. The Biogas Technology Advisory Committee was part of the ongoing commitment to finalize the Technology Assessment for biogas engines. In October 2010 staff met with the regulated community to discuss cost issues related to the emission standard adopted as part of the 2008 amendment. Since the July 2010 Interim Report, the Biogas Technology Advisory Committee met in September 2011, January 2012, April 2012, ~~and~~ May 2012, and August 2012. Two Public Workshops were held in February 2012 and April 2012. Staff also has had several meetings with control equipment vendors and also manufacturers of emerging technologies that may provide an alternative to electrical power generation by traditional internal combustion methods. In addition, staff has met individually with nearly every biogas facility operator to discuss site-specific issues, technologies, long-term plans for existing biogas engines, and costs. Several site visits were also conducted by staff at affected facilities.

CHAPTER 2: CONTROL TECHNOLOGIES

INTRODUCTION

BIOGAS CLEANUP

CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION

NOXTECH

ALTERNATIVE TECHNOLOGIES

INTRODUCTION

Controlling emissions for lean-burn biogas engines has many challenges. Fortunately, the same add-on control technologies used in the control of lean-burn natural gas engines can be employed in biogas engines with proper fuel pretreatment. Additionally, other technologies have emerged that have been shown to result in emissions well below the proposed rule limits.

The Final Technology Assessment attached to this staff report summarizes staff's findings to date regarding the feasibility of the biogas engine emission limits. Data collected from a completed demonstration project in the Basin and from a landfill in the Bay Area provides substantial evidence in support of the proposed emission limits for biogas engines. In addition to feasibility, the Final Technology Assessment also includes cost-effectiveness, compliance schedule, global warming impacts, and the impacts of potential flaring. The Final Technology Assessment provides a complete description of the control technologies for this amendment, and is presented as an attachment to this document (Attachment A). What follows is a summary of the technologies discussed in the Technology Assessment.

BIOGAS CLEANUP

As mentioned in the previous section, the cleanup of the inlet fuel for biogas engines can serve two purposes: longer operating time with less engine maintenance and protection of post-combustion catalysts from impurities. Methylated siloxanes in the biogas are a chief contributor to catalyst fouling and increased engine maintenance. The 2008 Interim Technology Assessment concluded that an engine with a gas cleanup system capable of effectively removing siloxanes can protect post-combustion catalysts and make multi-pollutant reductions feasible. Although the levels of siloxanes can vary by facility, a properly designed system can perform effectively to remove siloxanes as well as many other impurities such as moisture, particulates, VOCs and sulfur compounds. Two installations in California have shown that gas cleanup can protect catalysts and lower engine maintenance costs. The installations at Ox Mountain Landfill in the Bay Area and at the Orange County Sanitation District (OCSD) utilize gas cleanup systems and post-combustion catalytic control systems that have resulted in favorable reductions in NOx, VOC, and CO, while performance data demonstrates effective siloxane removal and protection of post-combustion catalysts. There are two main types of systems for siloxane removal, regenerative and non-regenerative. Ox Mountain uses a regenerative system, while OCSD relies on a non-regenerative system. However, the gas cleanup systems at both Ox Mountain and OCSD use activated carbon as the adsorption media for the gas impurities. The difference is that Ox Mountain heats the carbon and purge gas in a regenerative cycle to "reactivate" the carbon whereas OCSD simply replaces the spent media with fresh activated carbon.

CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION

A technology that has been around for many years for natural gas ICE after-treatment is catalytic oxidation and selective catalytic reduction (SCR). Catalytic oxidation removes VOC and CO from the exhaust stream while SCR removes NOx with the use of urea injection. This technology is most effective in lean-burn engines. Before effective gas cleanup became available, catalyst poisoning was a problematic issue with this application for biogas engines. The pilot study at OCSD and the installation at Ox Mountain both used these two technologies in conjunction with biogas cleanup for removal of NOx, VOC, and CO. The results from OCSD's pilot demonstration and Ox Mountain show that the proposed rule's emission limits are achievable on a consistent basis. Source test and CEMS data from both installations show that properly cleaned biogas does not foul or poison the oxidative and SCR catalysts, ensuring reliable multi-pollutant removal.

NOXTECH

NOxTech is a selective non-catalytic reduction control technology that treats the exhaust stream of IC engines, reduces NOx, VOC, and CO, and does not require gas cleanup. In the NOxTech system the exhaust gases are heated to a temperature that incinerates VOC and CO without generating thermal NOx, and then removes exhaust NOx using urea injection. Eastern Municipal Water District (EMWD) installed a NOxTech unit at a facility that operates three natural gas engines. The facility is currently operating the NOxTech system, but experienced some setbacks due to the high heat and rapid combustion created from the natural gas engine exhaust. An enhanced system with exhaust gas recirculation (EGR) has been installed and preliminary data has shown that the NOx limits are achievable. Further optimization is currently underway to establish consistent results. This system has the possibility of being less costly than the oxidation catalyst/SCR system because of potentially lower operations and maintenance costs, plus the added benefit of not requiring the high capital outlay of an inlet biogas cleanup system. It should be noted that the benefits of biogas treatment to engine wear and maintenance are forgone if a facility solely relies on NOxTech.

ALTERNATIVE TECHNOLOGIES

Other technologies exist that can be used in place of ICEs and are capable of producing much lower emission profiles. Fuel cells are capable of producing power electrochemically while producing near zero emissions. Fuel cells are sensitive to impurities; therefore, a gas cleanup system is essential. There are many fuel cell installations all over California running on anaerobic digester gas, including five in the South Coast Basin at wastewater treatment facilities.

Flex Energy combines regenerative thermal oxidation with microturbine technology for power production with near zero emissions. This system is especially applicable to facilities that produce low methane biogas, such as closed landfills. One system is operating at a military base in Georgia and a second is targeted to become operational in Orange County this year. This system does not require gas cleanup and can continue to provide power many years after a landfill closes and its methane production drops off.

Hydrogen Assisted Lean Operation, or HALO, is an emerging technology that involves the injection of hydrogen gas into the biogas fuel stream before combustion. This enrichment of hydrogen improves the lean limit combustion stability of the fuel, resulting in lower pollutant emissions. This technology is set to be tested and demonstrated at a wastewater treatment facility in the Basin.

Other combustion technologies such as gas turbines, microturbines, and boilers are also capable of producing power and have lower emission profiles than IC engines. Several facilities in the Basin already use these technologies as the sole source of power production or as a supplemental source to IC engines. Turbines and microturbines require gas cleanup, while boilers are less sensitive to impurities in the biogas.

SELF-GENERATING INCENTIVES

The California Public Utilities Commission (CPUC) offers incentives for facilities that produce at least 75% of their power from renewable fuels, such as biogas, and use that electricity to power internal operations. The Self-Generation Incentive Program (SGIP) provides incentives that can aid in offsetting some of the capital costs from biogas projects. As of November 2011, a $2.00 per Watt biogas incentive has been offered that can be added to other incentives based on the type of technology used, such as fuel cells, gas turbines, microturbines and IC engines. For example, the combined heat and power (CHP) fuel cell incentive is $2.25 per Watt, so if combined with the biogas incentive, the total incentive is $4.25 per Watt. So for a 1 MW CHP fuel cell installation running on biogas, the incentive would amount to 4.25 million dollars. The incentives are also contingent on the facilities meeting specific capacity factors and not exporting more than 25% of the power produced to the grid.

CHAPTER 3: SUMMARY OF PROPOSED RULE 1110.2

PROPOSED AMENDED RULE REQUIREMENTS

PROPOSED AMENDED RULE REQUIREMENTS

The key proposed amendments can be summarized as follows:

- Re-establish the effectiveness of the previously adopted 2012 limits. Allow biogas engine operators three and a half~~three~~ more years to comply with the 2012 emission limits. The new effective date will be January~~July~~ 1, 2016~~5~~ for all biogas engines.~~the first engine or a biogas cleanup system for the entire biogas engine fleet. The remaining engines will have an additional year to comply.~~
- Provide a compliance option with a longer averaging time to engine operators that can demonstrate through continuous emission monitoring (CEMS) data mass emission levels at least 10 percent lower than allowable under the rule's proposed concentration limits.
- Provide an alternate compliance option to give operators under long term fixed price power purchase agreements entered into prior to the February 1, 2008 amendments and extending beyond the January 1, 2016 compliance date additional time for engine retrofits beyond the proposed compliance date (up to two years) with the payment of a compliance flexibility fee.

The feasibility of the lower mass emissions was demonstrated by the recently completed pilot study by OCSD, which indicated that lower mass emissions can be achieved in conjunction with longer averaging times. This longer averaging time would be allowed provided that the CEMS data routinely shows NOx emission levels below 11 ppm (the proposed standard).

To reflect the additional time needed to complete the Final Technology Assessment, District staff is proposing to allow biogas engine operators more time for compliance with the emission limits adopted in the 2008 amendment. Subparagraph 1110.2(d)(1)(C) establishes the emission standards for biogas engines, specifies the effective dates for the emission limits, and provides the compliance schedule for all biogas engines, as listed in Table 3 on the next page. The table is split into two parts: The first part reflects the currently effective limits and the second part establishes the ~~3 to 4~~ three and a half year delay of the 2012 effective date limits for compliance. ~~For operators planning to add engine controls that do not require gas cleanup (i.e. NOxTech, H_2 injection), the first engine will have to comply by July 1, 2015, while the remaining engines will have one additional year to comply. For operators planning to add engine controls that do require biogas cleanup (oxidation catalyst/SCR), the biogas cleanup system servicing the entire biogas engine fleet will have to be installed by July 1, 2015, while the catalytic aftertreatment controls for all the engines will have to be installed by July 1, 2016.~~

Table 3. Proposed Concentration Limits for Biogas Engines

CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2016		
NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250
~~**CONCENTRATION LIMITS AND COMPLIANCE SCHEDULE FOR LANDFILL AND DIGESTER GAS (BIOGAS) FIRED ENGINES**~~		
~~**Category**~~	~~**Limit**~~	~~**Unit(s) Shall be in Full Compliance on or before**~~
~~First Engine or Biogas Cleanup System for entire Biogas engine fleet~~	~~NO_x (ppmvd)[1]: 11~~ ~~VOC (ppmvd)[2]: 30~~ ~~CO (ppmvd)[1]: 250~~	~~July 1, 2015~~
~~Remaining Engine(s)~~		~~July 1, 2016~~

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

[3] ECF is the efficiency correction factor.

The subparagraph in Rule 1110.2(d)(1)(C) that reads:

> "The concentration limits effective on or after July 1, 2012 shall become effective provided the Executive Officer conducts a technology assessment

> that confirms that the limits are achievable, and reports to the Governing Board by July 2010, at a regularly scheduled public meeting,"

will be removed due to the two year delay of the emission limit effective date for biogas engines, and the subparagraph's expired applicability.

Staff is proposing the following restructuring of paragraph (d)(1) to improve its readability. Subparagraph (d)(1)(D) is added to contain a provision that does not allow a biogas engine to operate in a manner that exceeds the emission limits in (d)(1)(C).

Subparagraph (d)(1)(E) provides an incentive for operators that achieve early compliance. Specifically, if a biogas engine achieves compliance by no later than January 1, 2015, that engine's permit application fees will be refunded to the owner or operator. It must be established to the satisfaction of the Executive Officer that a biogas engine is complying with the emission limits in Table III-B.

Subparagraph (d)(1)(F~~E~~) will specify the provision for the percentage of natural gas burned. This provision was relocated from subparagraph (d)(1)(C) of the current rule. Once a biogas engine complies with the proposed emission standards, the 10% natural gas limit will no longer apply.

Subparagraph (d)(1)(G~~F~~) will contain the exception for low-usage engines since it is not cost-effective to add controls to these units. This provision was also relocated from subparagraph (d)(1)(C) of the current rule.

Subparagraph (d)(1)(H~~G~~) will contain a provision for operators requiring a longer averaging time.

> "An operator of a biogas engine may determine compliance with the NOx and/or CO limits of Table III-B by utilizing a longer averaging time as set forth below, provided the operator demonstrates through CEMS data that the engine is achieving a concentration at or below 9.9 ppmv for NOx and 225 ppmv for CO (if CO is elected for averaging), ~~(~~each corrected to 15% O_2~~)~~, over a 4 month time period. An operator may utilize a monthly fixed interval averaging time for the first 4 months of engine operation and up to a ~~12~~ 24 hour fixed interval averaging time thereafter."

As evidenced by the demonstration project by Orange County Sanitation District (OCSD), there were occasional spikes in the NOx CEMS readings that were above the 11 ppm limit. This occurred approximately 0.9% of the time. To ensure compliance with the proposed limits, staff is proposing to allow biogas engine operators a longer averaging time beyond 15 minutes. However, this is contingent on the performance of the control equipment determined by a CEMS. The longer averaging time will be allowed if the NOx and/or CO emissions are at least 10% below what is allowable (at or below a concentration of 9.9 ppmv for NOx and 225 ppmv for CO). For the first four months of operation, a monthly averaging time will be allowed for the purposes of equipment optimization. After four months, a twenty four~~twelve~~ hour averaging time can

be implemented to demonstrate compliance. The longer averaging periods are fixed interval (or block) averages, not rolling averages. The longer averaging time may be used only if an engine is achieving the NOx and/or CO emission levels (9.9 ppmv and 225 ppmv, respectively) averaged over a 4 month period.

Since Rule 1110.2 does not require a CO CEMS on lean-burn engines, the requirements of subparagraph (d)(1)(H) apply to CO only if a biogas engine operator elects to install a CO CEMS for improved, real-time monitoring (e.g. oxidation catalyst performance). ~~The longer averaging option is not intended to apply to time-shared CEMS, since this type of system does not collect data continuously over the required time periods in the proposed rule.~~

To prevent artificial averaging of zero data when, for instance, the engine is not operating, or when the CEMS is undergoing periods of calibration or audit, clause 1110.2(d)(1)(H~~G~~)(i) will read:

> "For ~~the~~ purposes of determining compliance using a longer averaging time: An operator shall not average data during one-minute periods in which the underlying equipment is not operated or when the CEMS is undergoing ~~periods of calibration or audit~~zero or calibration checks, cylinder gas audits, or routine maintenance in accordance to the provisions in Rules 218 and 218.1."

The operation of the CEMS shall comply with the existing requirements of Rules 218 and 218.1. Rule 218.1 requires that the data points for CEMS analyzers are to be within 10 and 95 percent of the full span or full scale range. In addition, if any data point falls above 95 percent of the full scale range, that value shall be invalid for quantification. For a biogas engine using a longer averaging time, if a CEMS reading falls above 95 percent of the full scale range while the engine is operating, the invalid data point would not be factored into the longer averaging period. Furthermore, the magnitude of the excursion would be unknown since it is outside the range of the analyzer. To address these excursions, a missing data procedure will be applied to quantify the excursions for inclusion into the calculation of the longer averaging time.~~Whenever valid CEMS emission data cannot be obtained or recorded, aside from documented malfunctions and breakdowns, a missing data procedure will be applied.~~ For biogas engines, the NOx missing data shall use a concentration of 3~~36~~ ppmv (corrected to 15% O_2) for every missing time period above 95 percent of the full scale range and the CO missing data shall use a concentration of 750~~2000~~ ppmv (corrected to 15% O_2), if the engine is operating during these excursions. This is equivalent to three times the NOx and/or CO emissions limits in Table III-B.~~If the CEMS cannot obtain data per the requirements of AQMD Rules 218 and 218.1, then the substitute data must be used.~~ Clause 1110.2(d)(1)(H~~G~~)(ii) will read:

> "~~For purposes of determining compliance using a longer averaging time: An operator shall use substitute CEMS data for all other one-minute CEMS data when NOx and/or CO emissions data has not been obtained or~~

> ~~recorded or does not meet the requirements of Rules 218 and 218.1. A concentration of 36 ppmv for NOx and 2000 ppmv for CO (each corrected to 15% O_2) shall be used as substitute data.~~Notwithstanding the requirements of Rules 218 and 218.1, for one-minute time periods where NOx and/or CO CEMS data are greater than 95 percent of the Rule 218.1 Full Scale Range while the underlying equipment is operating, an operator shall use substitute data. A concentration equivalent to 3 times the NOx and/or CO emission limits in Table III-B (each corrected to 15% O_2) shall be used as substitute data."

The~~is~~ following provision discourages the intentional shutdown of a CEMS for reasons other than valid malfunctions and~~,~~ breakdowns~~, or inability to meet the requirements of Rules 218 and 218.1~~. Clause (d)(1)(H)(iii) clearly states that:

> "The intentional shutdown of a CEMS to circumvent the emission limits of Table III-B while the underlying equipment is in operation shall constitute a violation of this rule."

The longer averaging option is not intended to apply to time-shared CEMS, since this type of system does not collect data continuously over the required time periods in the proposed rule. This is stated in clause (d)(1)(H)(iv).

The revised staff proposal provides some biogas engine operators who have entered into fixed price, long term power purchase agreements with local utilities, prior to the February 1, 2008 amendments that first established the July 2012 biogas engine emission limits, with the option to defer compliance by up to two years from the January 1, 2016 compliance date, up to January 1, 2018 with the payment of a compliance flexibility fee. Subdivision (h) outlines the requirements for the plan submittal and the calculation of the compliance flexibility fee. The fee is based on the Carl Moyer cost effectiveness of $17,200 per ton and is calculated based on the NOx reductions of PAR 1110.2. The total cost per year is divided by the sum brake horsepower (bhp) of all the affected biogas engines to arrive at $47 per bhp per year. The compliance flexibility fee is calculated by taking the fee rate ($47/bhp-yr) and multiplying by the rated brake horsepower of the unit and then multiplying by the number of years to defer (1 or 2 years). The fees collected from this alternate compliance option will applied to AQMD NOx reduction programs. This alternate compliance option is not available for operators who have entered into long term power purchase agreements following the February 1, 2008 amendments.

The proposed amendments will provide biogas engine facilities with additional time to implement the proper controls to meet the emission limits. Biogas operators will also have additional time to explore the use of alternative technologies that do not require the combustion of biogas by internal combustion engines.

Several minor administrative changes were also included to provide clarity with respect to references within the rule. In addition, the following four clarifications, although

minor in nature, necessitate either a change in the rule language or an explanation detailed below.

The first clarification involves adjustments to oxygen sensor set points and the frequency of portable analyzer checks in Rule 1110.2 subclause (f)(1)(D)(iii)(I). In the current rule if an engine is in compliance for three consecutive emission checks without any O_2 set point adjustments, the engine can move up to a monthly testing schedule or test every 750 hours, whichever occurs later. If an engine then encounters a non-compliant emissions test result or if the O_2 sensor is replaced for a rich-burn engine with a three way catalyst, it must revert to the more frequent testing schedule. The objective of periodic monitoring is to prevent non-compliance and the objective of not allowing any O_2 set point adjustments during the emission tests is to prevent circumvention of the rule. However, if an operator is proactively adjusting the O_2 set points as a means of preventing a non-compliant situation, the current construct of the rule would suggest that the operator is still required to return to the more frequent testing schedule. Clearly, the intent of the rule was never to discourage such proactive maintenance approaches. To address this, the portable analyzer testing frequency can remain unchanged if the engine is in compliance before and after the O_2 set point adjustment at the air-to-fuel ratio controller (AFRC). This will maintain compliant operation of the engine without allowing the emissions to reach a non-compliant level, while preventing a reversion to a more frequent testing schedule. The operator must perform an emissions check after the set point adjustment to ensure that the engine is operating in compliance after the set point change. This post-adjustment testing is to be performed notwithstanding the requirements of subclause (f)(1)(D)(iii)(IV), which prohibits any control system tuning within 72 hours prior to an emission check. Subclause 1110.2(f)(1)(D)(iii)(I) will now read:

> "If an engine is in compliance for three consecutive emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant emission check or, for rich-burn engines with three-way catalysts, the oxygen sensor is replaced. <u>When making adjustments to the oxygen sensor set points, returning to a more frequent emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments, notwithstanding the requirements of (f)(1)(D)(iii)(IV).</u>"

The second clarification involves the shutdown period for an engine. The current rule provides up to 30 minutes after an engine start-up for non-compliant emissions. Emission control equipment takes about 30 minutes from a cold start-up to attain a proper operating temperature to effectively remove pollutants and achieve compliant results. Engine operators have also experienced a similar situation during a gradual shutdown where there are non-compliant events, specifically documented on those engines equipped with CEMS. Engine operators often need to shut an engine down over a short period of time (typically no more than 30 minutes) to allow it to cool and prevent

unnecessary damage from a hard stop. Under the current rule, many operators have to shut down an engine quickly to prevent non-compliant results and potential enforcement action. To address this issue, the exemption in Rule 1110.2(h)(10) will also include a 30 minute shutdown period in addition to the 30 minute start-up period. The emissions provisions in subdivision (d) shall not apply to:

> "An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment, and an engine shutdown period. The periods shall not exceed 30 minutes, unless the Executive Officer approves a longer period not exceeding 2 hours for an engine and makes it a condition of the engine permit."

The third clarification also involves an exemption in subdivision (h). Rule 1110.2(h)(11) allows an exemption of emission requirements for four operating hours when starting up an engine after an overhaul or major repair that involves the removal of the cylinder head. During these types of repairs, particles or liquids can be left behind from the engine work and take some time to burn off or expel. If an engine catalyst is in operation during this start-up period, significant damage can result from the operation of the engine. Physical damage to the catalyst can result from the particulates and a decrease in catalyst performance can result from contaminant poisoning. This impact can be immediate or can result in a sooner than expected catalyst replacement, which can become a significant cost to the operator. To prevent this from occurring, it has been noted that the four-hour exemption following an engine overhaul or major repair requiring removal of a cylinder head would also allow the temporary removal of the catalyst to prevent its damage.

The final clarification involves the testing and monitoring provisions in Rule 1110.2(f)(1)(D). Under the current rule, portable analyzer emission checks are performed in accordance to the testing frequency outlined in clause (f)(1)(D)(iii). In the event that a scheduled portable analyzer emission check occurs during the same monitoring period as a regularly scheduled source test per (f)(1)(C), the source test results can be used in lieu of the portable analyzer check. The reference source test methods in subdivision (g) of the rule are more stringent than the portable analyzer test method, so this clarification is being made in this report to prevent redundancy in testing within the same time period.

CHAPTER 4: IMPACT ASSESSMENT

EMISSIONS IMPACTS AND COST EFFECTIVENESS

INCREMENTAL COST EFFECTIVENESS

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) ANALYSIS

SOCIOECONOMIC ASSESSMENT

DRAFT FINDINGS UNDER CALIFORNIA HEALTH & SAFETY CODE SECTION 40727

COMPARATIVE ANALYSIS

EMISSIONS IMPACTS AND COST EFFECTIVENESS

The proposed amendments will have emissions impacts on biogas engines regulated by Rule 1110.2. Since biogas engines emit significantly more pollutants than natural gas engines and central power plants, the proposed emission standard will reduce NOx, VOC, and CO emissions drastically. On an aggregate pollutant basis, current biogas engine emissions are over 55 times higher than those of central power plants. The proposed amendments will result in up to 74% emission reductions (Figure 3).

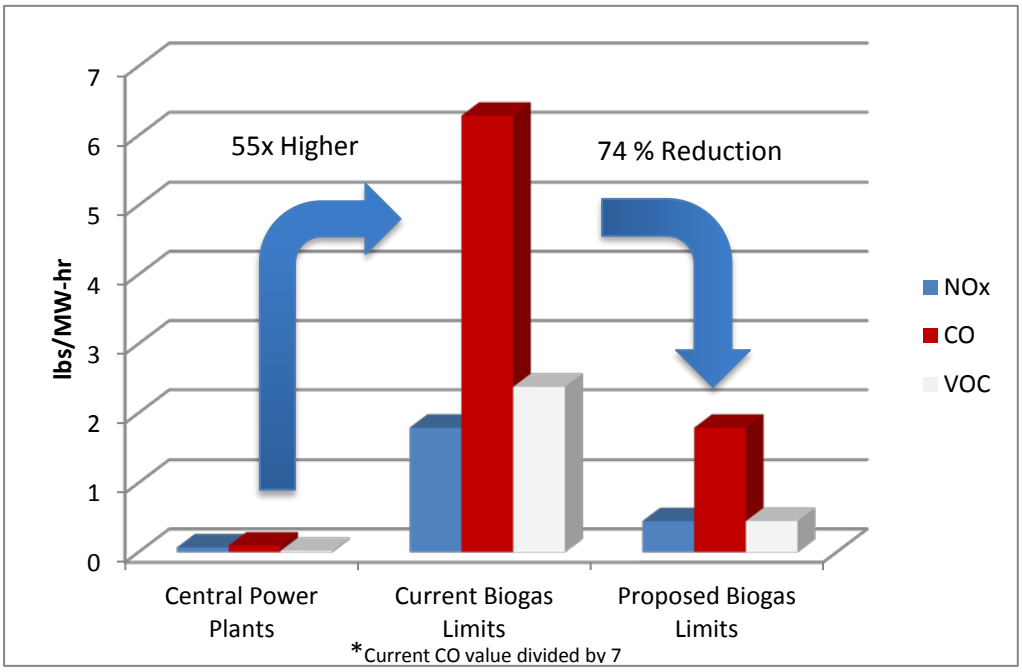

Figure 3. Emissions from Biogas ICEs versus Central Power Plants

The current emissions from biogas engines amount to approximately 1.3 tons per day of NOx, 0.8 tons per day of VOC, and 25.6 tons per day of CO. The current emissions are calculated from the current Rule 1110.2 rule limits and permit limits, while the future emissions are calculated from the proposed Rule 1110.2 limits. Permit limits were used for some engines because they were permitted at BACT or have more stringent permit limits than in the current rule. The emission reductions are 0.9 tons per day of NOx, 0.5 tons per day of VOC, and 20.0 tons of CO. The reductions will occur in two steps. The first reductions will occur by January~~July~~ 1, 2016~~5~~ and second step of reductions will occur one to two years later when all biogas engines will comply with the rule limits under the alternate compliance option.

Emissions are calculated for NOx, VOC, and CO. The emission reductions for CO are discounted by one seventh because its ozone-formation potential is approximately one seventh from that of NOx. For calculating cost effectiveness, the District uses the Discounted Cash Flow (DCF) model, which takes into consideration both capital cost

plus annual operating and maintenance costs. This use of this model is consistent with previous rulemaking proposals and past control measures because it links the cost of the project with its environmental benefits. The equipment is given a twenty year life and a 4% interest rate is applied. The calculated present worth value (PWV) is then divided by the summation of the emission reductions and the length of the project (20 years).

The cost figures submitted by OCSD from their final report were used as a benchmark for evaluating costs for several biogas engine operations. The OCSD data which includes operations for the highest brake horsepower portion of the engine distribution (3,471 bhp) were scaled across different digester and landfill gas engine sizes to estimate installation and operating costs for different engine sizes, ranging from 250 bhp to 4,200 bhp. The non-catalyst installed cost was calculated by using the general chemical engineering cost estimating practice for industrial equipment packages of $bhp^{0.6}$. The other costs were scaled based on brake horsepower alone.

The cost effectiveness was estimated to range from $1,700 to $3,500 per ton of NOx, VOC, and CO/7 reduced. 8,000 annual operating hours was assumed for the engines. The cost effectiveness was also calculated for a landfill installation with a more expensive regenerative gas cleanup system. These costs were obtained from the Bay Area AQMD for the installation at Ox Mountain Landfill. The cost effectiveness calculated using Ox Mountain's capital and operating costs for the proposed amended rule's emission reductions is $2,300 per ton of NOx, VOC, and CO/7. Staff also calculated cost effectiveness to account for additional gas cleanup and associated contingencies, based on stakeholder feedback. Using vendor quotes for gas cleanup systems, two additional cost effectiveness curves were created reflecting the additional gas cleanup and an added 20% capital cost contingency. The upper cost effectiveness curve has a range from $2,600 to $5,900 per ton. The upper and lower (base level) curves create a band that accounts for equipment contingencies. In addition, all of the cost effectiveness calculations reflected a two-year catalyst life to reflect a partial deactivation of OCSD's oxidation catalyst after two years of operation. Although the CO emission levels were elevated and still in compliance with the proposed limit, the calculations were revised to reflect a two-year, instead of a three-year, catalyst life. The cost effectiveness ranges are illustrated in Figure 4 for digester gas engines and Figure 5 for landfill gas engines.

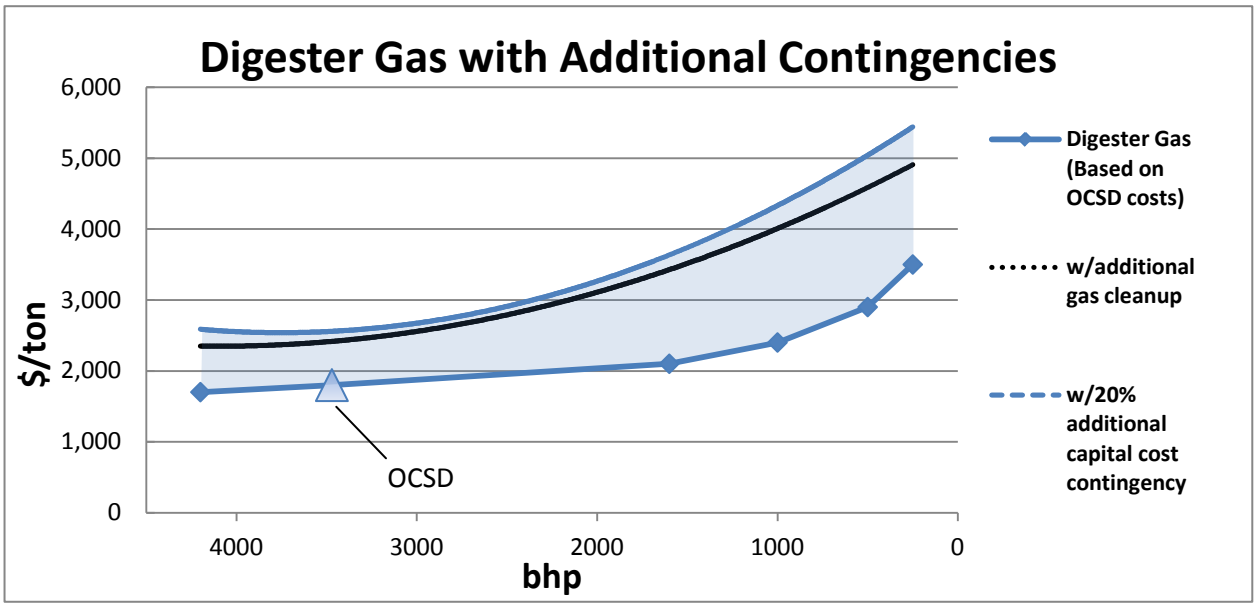

Figure 4. Cost Effectiveness for Digester Gas (Catalytic Aftertreatment)

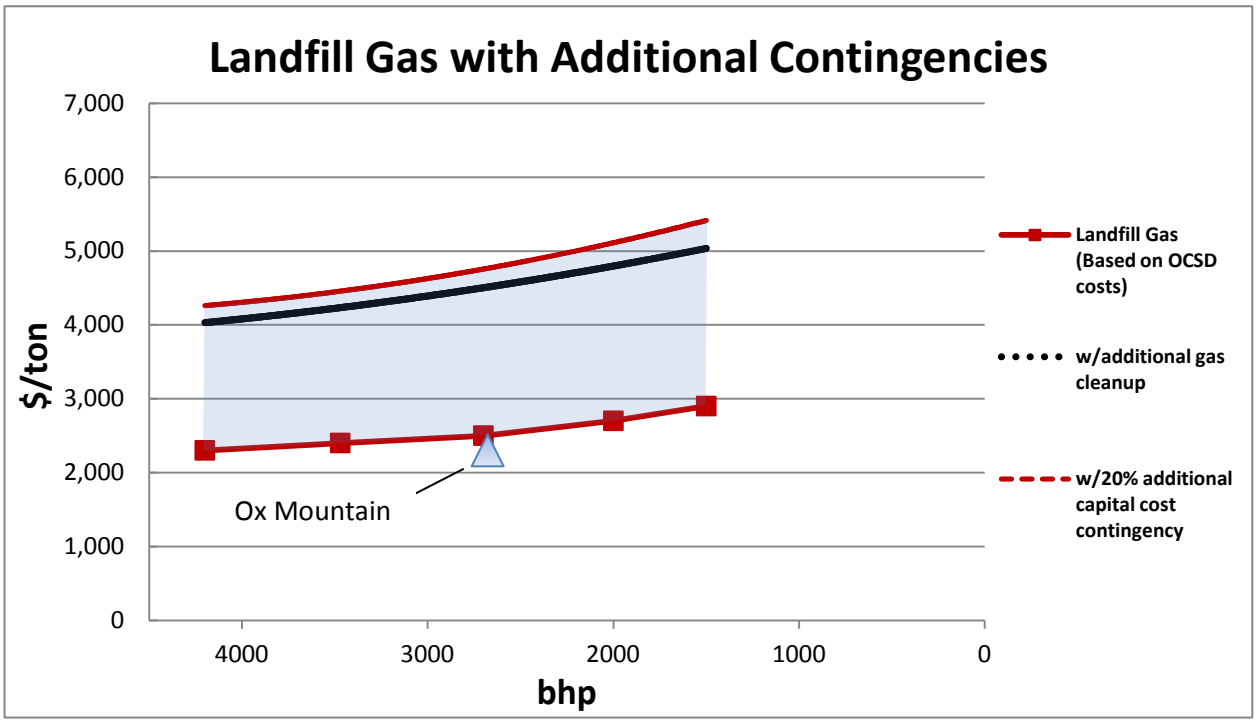

Figure 5. Cost Effectiveness for Landfill Gas (Catalytic Aftertreatment)

For catalytic control technology, the capital cost for the base level scenario on a per engine basis is expected to range from $417,000 for a 250 bhp engine to $2,706,000 for a 4,200 bhp engine. The capital cost range with added contingencies is $494,000 to

$3,147,000. These ranges represent the capital costs for the smallest engine to the largest in the biogas inventory.

The cost effectiveness estimates are within the costs presented to the Governing Board for past rulemakings. Digester gas and landfill gas engines of all sizes are shown to be cost-effective. The details of the cost effectiveness calculations with a detailed breakdown of the installation and operating costs are presented in the Technology Assessment (Attachments A and B).

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (BARCT) rules or emission reduction strategies when there is more than one control option that would achieve the emission reduction objective of the proposed amendments, relative to ozone, CO, SOx, NOx, and their precursors. The proposed control option is biogas cleanup, with oxidation and SCR catalyst control, while the alternative control option is shutting down the engines, purchasing electricity from the grid, and flaring the biogas. To determine the incremental cost effectiveness, the calculated difference in the dollar cost between the two control options is divided by the difference in their emission reduction potentials.

The basis for the control options is the OCSD pilot study demonstration project engine (2500 kW). To calculate the cost to purchase the power from the grid, the present worth value (PWV) of the electricity produced by the engine is calculated using its size and its annual hours of operation (6,000 hours) at a nominal rate of $0.08 per kW-hr. The present worth calculation assumes a 4% interest rate and a 20 year program life. The present value of the operations and maintenance (O&M) costs is also factored (subtracted from the electricity costs) since these are costs that will be avoided if the engine is no longer in service. The engine maintenance costs are twice the upper value for a natural gas ICE ($0.014 per kW-hr). The total proposed project cost (PWV of OCSD engine with controls) is then subtracted from the PWV of the total project alternative project cost (purchasing electricity).

The emission reductions of the alternative project are calculated by using the net emissions of removing an engine from service and factoring the emissions from flaring and from a central power plant to replace the engine power produced. The emission reductions from removing the engine from service are calculated for NOx, VOC, and CO/7, using emission factors based on the current Rule 1110.2 compliance limits (at 6,000 annual operating hours and a 20 year program life). The flare emissions are calculated using the fuel consumption (permit limit) and existing (average limit) flare emission factors for NOx, VOC, and CO. The total emissions for flaring over 20 years are calculated for NOx, VOC, and CO/7. Next, the central power emissions are calculated using emission factors based on central power plant BACT emission standards. It was assumed that 50% of the power replaced would come from the central power plant. The emissions over 20 years were then calculated for NOx, VOC, and CO/7. The sum of

the flaring and central power plant emissions are then subtracted from the engine emission reductions to obtain the net emission reductions of the alternative control option.

Finally, the emission reductions of the proposed control option are factored into the final calculation (from present rule limit to proposed rule limit at 6,000 annual operating hours over 20 years). The difference of the PWV of the alternative control option and the proposed control option is divided by the difference in the emission reduction potentials for both projects. If "a" is the alternative control option and "p" is the proposed control option, then the incremental cost effectiveness is:

$$(C_a - C_p) / (E_a - E_p) = \$757{,}100/\text{per ton}$$

The calculated value clearly indicates that the alternative control option is not viable when compared to the proposed controls.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and AQMD Rule 110, SCAQMD staff has reviewed PAR 1110.2 to identify the appropriate CEQA document for evaluating potential adverse environmental impacts. Because the proposed project consists of changes to a previously approved project evaluated in a certified CEQA document and none of the conditions described in CEQA Guidelines §15162 calling for preparation of a subsequent CEQA document would occur, staff has concluded that an Addendum to the December 2007 Final Environmental Assessment: Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs), prepared pursuant to CEQA Guidelines §15164, is the appropriate CEQA document for the proposed project. Pursuant to CEQA Guidelines §15164(c) an addendum need not be circulated for public review. However, upon completion, the Addendum as well as the February 2008 Final Environmental Assessment will be available to the public at AQMD Headquarters or by calling the AQMD Public Information Center at (909) 396-3600.

SOCIOECONOMIC ASSESSMENT

PAR 1110.2 would re-establish the concentration limits for biogas-fired engines for a later time, that is from 2012 to 20~~15/~~16. Furthermore, the universe of affected biogas-fired engines by PAR 1110.2 is currently at 55 engines, reduced from 65 engines evaluated as part of the 2008 amendments, which is a reduction of 14 percent of the total bhp.

The technologies for complying with the concentration limits have remained the same since 2008 and costs of these technologies have stayed relatively constant. According to the February 2008 Socioeconomic Report for Rule 1110.2, the 2011 present value (including capital, operating and maintenance costs) of SCR/Oxidation Catalyst/Biogas

Cleanup System for large biogas engines (>1,500 bhp) was $3.37 million over a 20-year period. The actual present value of a similar system (with catalyst replacement every three years) at OCSD was $3.09 million. Based on catalyst replacements every two years, AQMD estimates the present value of the same system to be $3.47 million.

The additional time for compliance and fewer affected engines would result in overall savings to the affected universe as a whole, compared to what was analyzed as part of the 2008 amendments. Therefore, given the fact that there are fewer engines to control and the control costs remained relatively constant compared to what was evaluated as part of the Socioeconomic Assessment conducted for the 2008 amendments to Rule 1110.2, the findings and conclusions of that analysis remain valid for this proposed amendment as well.

That 2008 Final Socioeconomic Assessment will be available to the public at AQMD Headquarters or by calling the AQMD Public Information Center at (909) 396-3600.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH & SAFETY CODE SECTION 40727

California Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report. In order to determine compliance with Sections 40727 and 40727.2 a written analysis is required comparing the proposed rule with existing regulations.

The draft findings are as follows:

Necessity: PAR 1110.2 is necessary to reduce emission limits from combustion equipment in order to meet federal and state ambient air quality standards for ozone and PM 2.5.

Authority: The AQMD obtains its authority to adopt, amend, or repeal rules and regulations from California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, and 41508.

Clarity: PAR 1110.2 has been written or displayed so that its meaning can be easily understood by the persons affected by the rule.

Consistency: PAR 1110.2 is in harmony with, and not in conflict with or contradictory to, existing federal or state statutes, court decisions or federal regulations.

Non-Duplication: PAR 1110.2 does not impose the same requirement as any existing state or federal regulation, and is necessary and proper to execute the powers and duties granted to, and imposed upon the AQMD.

Reference: In amending this rule, the following statutes which the AQMD hereby implements, interprets or makes specific are referenced: Health and Safety Code sections 39002, 40001, 40702, 40440(a), and 40725 through 40728.5.

COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, the AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed AQMD rules and air pollution control requirements and guidelines that are applicable to industrial, institutional, and commercial combustion equipment. A comparative analysis is not required if the District finds that the proposed rule does not impose a new emission limit or standard. The District makes that finding, since the 2012 limits are already existing and the proposed rule does not make it more stringent. Nevertheless, the District incorporates by reference the comparative analysis contained in the February 2008 Final Staff Report for PAR 1110.2, which is also updated below for changes.

National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards

Appendix F in the 2008 Final Staff Report for Proposed Amended Rule 1110.2 (February 2008) provides a detailed summary and comparison of the key elements of PAR 1110.2, the RICE NESHAP, and the NSPS. Appendix F is incorporated in this report by reference and is available at http://www.aqmd.gov/hb/2008/February/080233a.html. The proposed amendments of PAR 1110.2 are not in conflict with federal regulations.

AQMD Rules Applying to Stationary Gaseous- and Liquid-Fueled Engines

AQMD Rule 218 and 218.1 - Continuous Emission Monitoring Rules, which were amended on May 14, 1999, and May 4, 2012, respectively, set forth requirements for new, modified and existing continuous emission monitoring systems that include certification, development and implementation of a Quality Assurance/Quality Control Plan, recordkeeping, reporting, and performance specifications. PAR 1110.2 requires ICEs with required CEMS to comply with Rule 218 and 218.1.

AQMD Rule 401 – Visible Emissions, which was last amended on November 9, 2001, prohibits the discharge of emissions into the atmosphere from any single source for period or periods aggregating more than three minutes in any one hour which will cause: a dark or darker shade as that of a number 1 on the Ringelmann chart, as published by the United States Bureau of Mines, or of an opacity equal or greater than number 1 on the Ringelmann chart.

AQMD Rule 431.1 – Sulfur Content of Gaseous Fuels, which was last amended on June 12, 1998, prohibits the sale and use natural gas with a sulfur content exceeding 16 ppm. Rule 431.1 also prohibits the sale and use of the following gases with a sulfur content

exceeding: 150 ppmv in landfill gas; 40 ppmv in refinery gas, sewage digester gas and other gases.

AQMD Rule 431.2 – Sulfur Content of Liquid Fuels, which was last amended on September 15, 2000, prohibits the purchase by stationary source end users of any diesel fuel with a sulfur content exceeding 15 ppm on and after June 1, 2004.

AQMD Rule 1303 - New Source Review Requirements, which was last amended on December 6, 2002, requires BACT, modeling and emission offsets for any new or modified source which results in an emission increase of any nonattainment air contaminant, ozone depleting compound or ammonia.

AQMD Rule 1401 - New Source Review of Toxic Air Contaminants, which was last amended on September 10, 2010, specifies limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazard index (HI) from new, modified and existing permitted sources which emit toxic air contaminants (TACs) listed in Table I of Rule 1401. Although numerous TACs may be emitted from engines, formaldehyde, acrolein, methanol, and acetaldehyde account for essentially all of the mass emissions. PAR 1110.2 target pollutants are NOx, VOC and CO.

AQMD Rule 1470 - Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, which was amended on May 4, 2012, addresses primarily toxic diesel PM from new and existing, stationary, emergency and non-emergency, diesel engines, whereas Rule 1110.2 addresses only NOx, VOC and CO emissions.

AQMD Regulation XX - Regional Clean Air Incentive Market (RECLAIM) superseded many Regulation IV and Regulation XI rules for NOx and SOx for the largest facilities with an emission trading program that achieved equivalent emission reductions, but in a way to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx by methods such as add-on controls, equipment modifications, reformulated products, operational changes, shutdowns, and the purchase of excess emission reductions. Facilities for which emission fee data for 1990 or subsequent year shows four or more tons per year of NOx or SOx, excluding certain exempt sources, are subject to this program. Regulation XX specifically identifies requirements for ICEs, in addition to other specific sources, which include monitoring, reporting and recordkeeping for NOx and SOx emissions. PAR 1110.2 would apply to VOC and CO emissions from IC Engines from these sources.

While only applicable to new electrical generating engines, the CARB 2007 Distributed Generation Regulation is discussed below.

CARB 2007 Distributed Generation Regulation

Beginning in 2007 CARB required new Distributed Generation (DG) units sold in the state to be certified by meeting emission standards that are at least equivalent or more stringent than those for large central power generating stations with BACT. The emission standards are applicable unless engines are not exempt from any District requirements. In addition, the regulation calls for currently permitted equipment to meet the more stringent emission standard by the earliest practicable date. Biogas fueled ICEs subject to the CARB regulation installed after January1, 2013 must meet the emission standards of large central power generating stations with BACT.

ATTACHMENT A

PAR 1110.2 PUBLIC COMMENTS AND RESPONSES

Technical Feasibility

Comment: There is no reliable hard data that documents the successful operation of a landfill gas to energy facility. SCR and gas cleanup for siloxane removal hasn't been proven.

Response: While the demonstration projects in our Basin focused on digester gas-powered biogas engine control systems, such systems are directly applicable to landfill gas-powered biogas engines. This holds true for the oxidation catalyst/SCR based system of the successfully completed pilot study by the Orange County Sanitation District as well as the other control technologies of the ongoing demonstration projects. The feasibility of biogas cleanup/oxidation catalyst/SCR-based controls on a landfill gas-powered biogas engine has been demonstrated by Ameresco at Ox Mountain Landfill in the Bay Area. Staff conducted a site visit to Ameresco's facility at Ox Mountain Landfill and verified that the equipment has operated successfully for almost three years with gas cleanup, oxidation catalyst, and SCR. With the exception of some operational challenges during commissioning and start-up, the equipment has been effective in meeting the proposed rule's emission limits. Ameresco's TSA system has never experienced a siloxane breakthrough and consistently removes siloxanes effectively. Gas cleanup for siloxanes has been in use at landfills is an established technology, as these systems are currently in use for the protection of landfill gas-fired turbines.

Comment: Flaring biogas is undesirable, but may be necessary if the costs of controls become too prohibitive.

Response: Staff agrees that the flaring of biogas is undesirable, especially since it is a renewable resource. However, if a facility decides to flare the biogas and purchase the lost power from a central power plant, the criteria pollutant impacts will be lower than operating the biogas engines and, although elevated, the greenhouse gas (GHG) will not be significant.

Comment: Staff should take into account and analyze the recent deactivation of OCSD's oxidation catalyst due to siloxanes in terms of added costs.

Response: Until staff receives and independently reviews the laboratory results, it is premature to say that siloxanes were the cause of the elevated emissions or conclude that the oxidation catalyst failed. Staff agrees that the elevated CO emissions above 100 ppmv are not what the facility is accustomed to and provided a reasonable cause for concern, but the emission levels were still well within compliance when the oxidation catalyst was removed from service. In spite of the uncertainty associated with the CO emission increase and to account for the potentially more frequent catalyst replacement needed, staff has adjusted the annual operating costs to reflect a 2 year life for the catalyst instead of a three year life. Even with the increased catalyst replacement frequency, the controls remain cost effective. Please note that Ox Mountain has also experienced a similar elevation of CO emissions during its three years of operating six engines, but the

facility has not had to replace a catalyst throughout its entire operation due to deactivation.

Comment: Staff should conduct a site-by-site analysis of landfill lives for cost effectiveness. Some landfills are already closed and the 20 year life would not be realistic for any new equipment.

Response: There is an element of uncertainty associated with the closure of a particular landfill site. For example, one landfill site was scheduled for closure within the next few years. It is now our understanding that this same site may remain operating for several more years due to a decrease in the amount of waste deposited at that site. Also under consideration should be the fairly low cost-effectiveness of the proposed amendment. On this basis, a proposed project would still be marginally cost-effective with an equipment life much less than the assumed 20-year life. For example, the shortest term power purchase agreement from one of the affected private operators is nine years. Even with a nine year equipment life, the highest peak value of cost effectiveness is $13,100 per ton. This value is well within the cost effectiveness of previously adopted or amended NOx rules. For these projects there is a salvage value associated with the installed equipment, a value that was not accounted for in the proposed 20-year life project. Ultimately it is a business decision unique to the particular facility operator to shut down the site prior to rule implementation in 2016~~5~~, install the proposed control equipment, opt for one of the alternate control options (e.g., flex energy), or burn the fuel in other existing equipment (e.g., boilers and flares), if available.

Comment: Stakeholders have not received any substantial information and data regarding Ox Mountain's ability to continue to comply with the proposed emission limits.

Response: Staff conducted a site visit to the facility in April and received a wealth of information from the facility operators. This information is provided in the Technology Assessment. In addition, staff has requested more complete CEMS data and is currently awaiting its receipt. Upon receipt and analysis, Staff will make the information available to the stakeholders.

Comment: SCR technology is not scalable to smaller engines.

Response: Based on communication with technology vendors, SCR systems are scalable to the engines of all sizes, including the smallest in the biogas engine inventory. These vendors have been producing catalytic controls for over 2 decades on a wide variety of equipment and for engine sizes within the scope of this rule amendment. The control systems in SCR units are a standard size and are provided at a fixed cost. The catalyst volume is dependent on the horsepower of the engine and the outlet flow produced, but is a smaller part of the total price for smaller engines. The catalyst price and housing size actually begins to increase for higher horsepower engines and flows since more catalyst blocks are required. SCR systems have been installed on a wide range on engine sizes, including the size range of the biogas engines subject to this regulation.

Comment: Commercial, cost-effective technologies are not available.

Response: In staff's Technology Assessment, Oxidation Catalyst/SCR with gas cleanup has been identified as feasible, cost-effective technology. Once biogas is cleaned the catalysts perform at the same level as natural gas-fired engines.

Comment: Biogas is not natural gas and biogas engines should not be subject to the same emission restrictions as natural gas engines.

Response: The difference between biogas and natural gas is the methane content and, hence, the BTU level. Installations exist today that convert biogas into high BTU gas that can actually be injected into the natural gas pipeline. There are also gas cleanup systems in the District that currently clean landfill gas for powering gas turbines. Staff feels that when properly cleaned, biogas can run an engine with controls and should be subject to the same requirements as those for natural gas engines, especially when the emissions from current biogas engines are 55 times higher than those of central power plants.

Operational/Compliance

Comment: NOx excursions above the compliance limit will be expected at landfill sites. Maintaining the efficiency correction factor (ECF) would help to accommodate these excursions.

Response: Staff's proposal of using a longer averaging time will actually benefit a facility better than using the ECF. For example, an engine with an ECF of 1.25 will have a NOx limit of 13.75 ppmv. The longer averaging time proposed in the rule will aid in addressing spikes that are much higher than 13.75 ppmv, as long as the equipment is consistent in meeting lower mass emissions.

Comment: The operation of the NOxTech does not necessarily require an Air-to-Fuel-Ratio Controller (AFRC) to function properly. A rule provision should be added to make an allowance for an AFRC to be optional when operating the NOxTech.

Response: The rule allows for alternative controls with an equivalent environmental benefit to be maintained, approvable by the Executive Officer. On this basis, the use of the NOxTech, provided that it meets the rule limits, is potentially approvable.

Comment: Rule 1110.2 should be amended to make the breakdown provision consistent with that in Rule 430 in that a breakdown that results in the violation of any rule or permit condition be reported to the District within one hour of such event.

Response: The reporting provisions in Rule 430 and in Rule 1110.2 are both clear in classifying breakdowns that result in the violation of a rule or permit condition and those that result in excess emissions that violate a rule or permit condition. An operator has to be mindful of other rule or permit conditions, including those under Rule 430.

Comment: A shutdown provision should be added to the rule in addition to the 30 minute start-up exemption.

Response: Staff agrees with the commenter and has added the shutdown provision in the staff proposal to allow for proper cool down of engines and control equipment.

Comment: To remain in compliance, oxygen set points can be adjusted before going out of compliance. But the penalty incurred for this preventative measure is to return to a more frequent portable analyzer testing schedule.

Response: Staff agrees with the commenter and has included in the staff proposal the allowance for oxygen set point adjustments without returning to a more frequent portable analyzer testing schedule if the engine is in compliance before and after the set point adjustment.

Comment: When adhering to a portable analyzer testing schedule, some tests will coincide with a source test. A source test followed by a portable analyzer check at the same time is unnecessarily repetitive.

Response: Staff agrees with the commenter and has made a clarification in the Staff Report to allow source test results to be used in lieu of concurrently scheduled portable analyzer checks.

Comment: A clarification is needed to allow for the temporary removal of a catalyst for up to four hours after engine start-up following an engine overhaul or major repair requiring removal of a cylinder head. Oil and particulate contaminants from engine work can ruin a catalyst if it is operating during start-up.

Response: Staff agrees with the commenter and has made a clarification in the Staff Report to allow the temporary removal of a catalyst under the exemption provisions of Rule 1110.2(h)(11).

Comment: For operators of lean burn engines with low CO emissions, the currently required quarterly portable analyzer checks are unnecessary. Biannual source tests would be sufficient for compliance.

Response: The application of portable analyzer checks on a quarterly basis was the result of an extensive rule making process. The commenter will need to provide data to show that biannual source tests would be sufficient.

Comment: RECLAIM quarterly certification of emissions (QCER) reports are due within 30 days of the end of a quarter, but the Rule 1110.2 Inspection and Monitoring (I&M) reports are due within 15 days of the end of a quarter. RECLAIM facilities would like the submittal of the two reports to coincide at 30 days.

Response: It is not surprising that different rules will have different reporting requirements. These differences extend to both the content and submittal schedule of the reports. Unless the commenter can demonstrate the Rule 1110.2 reporting schedule should be lengthened, the current schedule will remain intact.

Comment: The proposed 24~~12~~ hour averaging time should be applied to CO as well as NOx.

Response: Staff agrees and has modified the staff proposal to extend the longer averaging time option to CO.

Comment: The proposed lowering of the CO and VOC emission levels for new distributed generation (DG) engines to the CARB DG standard is unattainable. Current, on-going projects that are barely capable of meeting the current rule standards will not be able to meet the proposed levels. Some new projects will have to cease, allowing old, grandfathered engines to continue to operate. With the San Onofre plant possibly shutting down, there could be significant implications with distributed generation in California.

Response: Based on the response from industry and the current status of the technology, staff will retain the current standard, but will consider lowering the standard to the CARB level in the future.

Compliance Schedule

Comment: The two year implementation deadline is not realistic for the design and construction of catalytic controls, especially for public agencies.

Response: Staff has revised its proposal to extend the compliance schedule to ~~3 and 4~~ three and a half years beyond the July 1, 2012 date, with up to 2 additional years for operators under long term fixed price power purchase agreements entered into before the February 1, 2008 amendments and extending beyond the January 1, 2016 compliance date with the payment of the compliance flexibility fee.

Comment: Other potential technologies seem infeasible with the current two to three year implementation schedule since they have not been proven to be effective.

Response: The Technology Assessment is providing ample evidence about the feasibility of controlling emissions from biogas engines through an oxidation catalyst/SCR control system in conjunction with a biogas cleanup system. The proposed ~~three to four~~ three and a half year implementation schedule will allow for additional

technology demonstration projects to complete and provide stakeholders with more choice and enough time to allocate funds, permit, construct, and install the equipment.

Comment: The compliance schedule should be conditional upon meeting certain technology demonstration goals by keeping the Technology Assessment open, thus allowing the technology to prove itself before committing to a schedule.

Response: Staff will commit to continue the technology review/implementation process and report back to the Stationary Source Committee beginning no later than~~by~~ July 1, 2013 to assure that the schedule for compliance is reasonable and to make appropriate recommendation on potential rule changes if necessary.

Cost Effectiveness

Comment: The cost analysis should be conducted using dollars per kW hour. This is more relevant to an operator's decision making to justify the project. The Interim Technology Assessment committed to analyzing costs using this metric.

Response: While it is difficult to perform this type of analysis since every single facility and operator affected by the proposed amendments is unique, Staff did calculate costs in dollars per kW hour in its analysis across the range of engine sizes with considerable contingencies. The fact remains that the environmental benefits are not reflected at all in a cost per kW hour calculation. As operators make decisions based on dollars per kW hour, our Governing Board has to make decisions based on the cost per ton of pollutants removed.

Comment: Existing gas cleanup equipment was used in OCSD and the costs for a brand new system should be included in AQMD's cost analysis.

Response: OCSD used its existing compressors and chillers for its gas cleanup. Other operators also have similar existing equipment. However, Staff has applied a 20% contingency to the equipment capital costs to account for the necessity of some facilities to install brand new equipment, such as compressors and chillers. These costs are reflected in Staff's cost effectiveness analysis.

Comment: The costs are based on OCSD low siloxane levels. There is no analysis for facilities with much higher siloxane loads, such as in landfill applications.

Response: OCSD changed its media three times during its year-long demonstration project. The cost analysis has also accounted for much more frequent carbon media change-outs (monthly), to account for scenarios with higher siloxane loads. This will obviously drive up the operational costs and is reflected in Staff's analysis as a cost contingency.

Comment: The emission reductions that Staff calculated for Ox Mountain are not considering the actual emission levels and overstate the emission reductions.

Response: For rulemaking, it is the standard practice to calculate emission reductions from rule or permit limits to the proposed limits. Actual emission levels and source tests are "snapshots" of a moment in time and, although compliant, may not accurately reflect the emissions for any other given time period. Please do note that if one considers the better than expected performance of the control technologies, arguably there are additional reductions that can be claimed above and beyond the proposed rule limits. Therefore, staff believes that calculating emission reductions from current limits to future rule limits, for the purposes of estimating cost effectiveness, is a reasonable approach.

Comment: Plants with less engines and less capacity will pay a much higher capital cost for gas cleanup.

Response: The size of the gas cleanup system is dependent on the overall fuel flow rate of the gas that will be used by the engines. Smaller fuel flows will require smaller media vessels. The operating costs will depend on the siloxane load and how often media change-outs are required.

Comment: Staff has not incorporated the costs submitted by the affected facilities into its cost effectiveness analysis.

Response: District staff solicited cost information from all the affected biogas facility operators and received detailed costs for half of these facilities. Based on the costs provided by the twelve facilities and applying emission reductions from existing to proposed rule limits, the current cost effectiveness range as submitted by the twelve facilities using the DCF model is $2,700 to $50,100 per ton of NOx, VOC, and CO/7. This is a wide range and is difficult to normalize based on the wide variety of cost assumptions submitted. OCSD's calculated cost effectiveness, including additional contingencies, amounted to $2,600 per ton. It should be noted that the OCSD's cost effectiveness is based on actual data, not estimated data by the twelve facilities. A cost effectiveness of $30,000 per ton roughly signifies the upper limit for rules presented to the AQMD Governing Board, based on past rulemakings. All of the cost submittals contained contingencies of varying degrees, and others added inflation rates to the cost estimates. These cost components have never been used in any of the past AQMD cost effectiveness analyses. The cost effectiveness of two facilities ($48,200 and $50,100 per ton) illustrates the effect of excessive contingencies added to the capital and operating costs. One facility had capital contingencies up to 50%, in addition to its project design and management contingencies. Some of the equipment costs are significantly higher than those provided by vendors, even with contingencies added. OCSD's operating costs in its final report were $58,950, while some of the others facilities' were orders of magnitude higher (as high as over 10 times). These excessively high contingencies and operating costs are inappropriate for a cost effectiveness analysis that has a reference point based on actual cost data. Even though the twelve facilities provided their own cost data, inflation rates, and contingency factors, only the two aforementioned facilities' cost effectiveness went above the Board-accepted cost effectiveness for recently amended

AQMD rules. Taking this into account as well as the cost effectiveness analysis based on actual cost data clearly indicates that the staff proposed rule amendment is cost effective.

Comment: No costs for additional maintenance for the gas cleanup system and catalyst controls as well as costs for lost electricity during maintenance were provided for Ox Mountain, which can drive up costs.

Response: Gas cleanup generally results in extending the engine's operating cycle and reducing the maintenance cycles and frequency during which engines must be taken out of operation and undergo expensive repairs. Longer operating cycles and reduced maintenance translate into more power produced and reduced operating costs. These cost savings were not identified by the commenter. Staff has added contingencies in its cost analysis to cover some of the potential costs identified by the commenter. With the contingencies added, the cost effectiveness is well within (by a factor of 6) the rough upper bound of $30,000 per ton, based on previous AQMD rulemakings. Consequently, even if costs for maintenance and reduced power production nominally increase for a particular installation adjusted with the previously mentioned cost savings, the resulting cost effectiveness would be well within the upper bound value and thus, still cost effective.

Space Limitations

Comment: The space limitations at some facilities would make it impossible to add oxidation catalyst and SCR controls to the engines.

Response: Catalyst manufacturers and installers have found innovative ways to design and construct structures and piping to accommodate varying configurations. For example, OCSD's project involved the construction of an elevated platform outside of the engine building to allow for vehicle traffic underneath. Other installations use elevated supports, roof-mounted supports, and even wall-mounted supports where plot space is very limited.

Financing Control Equipment

Comment: Existing power purchase agreements (PPAs) make it impossible to make any capital expenditures on control equipment. Any modifications would be economically infeasible and would likely lead to flaring.

Response: Staff has requested the PPAs from those affected for review by District Counsel, per the recommendation from members of the Stationary Source Committee at its April 2012 meeting. To date, staff has not received any PPAs from the affected facilities. It should be noted that the ongoing rule development process regarding the biogas engines was initiated well before the 2008 amendments, which provided the operators with more than adequate time to revise their PPAs prior to the future effective dates. Despite this, staff is proposing an alternate compliance option for these affected

facilities, which will provide up to two additional years for compliance beyond the January 1, 2016 compliance date, with the payment of a compliance flexibility fee. Only operators that entered into power purchase agreements prior to the February 1, 2008 amendments and that extend beyond the January 1, 2016 compliance date are eligible to benefit from the alternate compliance option.

Comment: The stakeholders need help in achieving a legislative fix to provide additional financial incentives for biogas energy projects.

Response: The AQMD will be a willing participant in the support of legislation that will provide additional financial incentives for biogas energy projects and has already taken support position on several pending legislations.

Comment: Current State legislation prohibits any landfill gas to pipeline projects. The stakeholders also need District support in helping stakeholders reach this goal.

Response: The AQMD will also be a willing participant in support of allowing stakeholders to inject clean landfill gas into the gas pipeline, provided it is cleaned up to reasonable specifications established by CPUC or State law.

GHG Impacts

Comment: Staff needs to consider criteria pollutant emissions that are offset from operating biogas engines and not flaring and purchasing electricity from the central power plants.

Response: Staff has considered the tradeoffs between generating electricity with biogas engines meeting current emission limits and central power plants. While increased flaring of biogas results in increased electricity generation from central plants to meet demand, the resulting criteria pollutant emissions impact from both central power plants and biogas flaring would be less than current engine emissions and, for GHG emissions, would be slightly higher. Staff has analyzed the impact of potential increased flaring in the staff report and in the Technology Assessment.

Comment: Staff needs to acknowledge the benefit of gas to energy projects as better overall for GHG emissions than flaring.

Response: AQMD staff acknowledges the benefits of biogas to energy projects. Since the South Coast is a non-attainment area for ozone, achieving criteria pollutant reductions is a priority for AQMD and CARB. In our GHG analysis, it is clear that the criteria emissions from flaring are lower than from biogas ICEs. Staff, however, is mindful that flaring is undesirable and understands the importance of maintaining the productivity of biogas to energy projects. Since biogas engines pollute significantly more than their natural gas counterparts and central power plants, it is staff's desire to decrease biogas ICE emissions by requiring controls which are both feasible and cost effective. Given the region's extreme non-attainment status with respect to the 8-hour ozone standard and

non-attainment status with respect to the PM2.5 standards, the superior criteria pollutant reduction benefits (especially in NOx) of the staff proposal (even with increased flaring) will more than compensate for the slight disbenefit in GHG emissions.