Bay Area Air Quality Management District
939 Ellis Street
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Bay Area 2005 Ozone Strategy
Further Study Measure FS 14

BAAQMD Regulation 9, Rule 10:
NITROGEN OXIDES AND CARBON MONOXIDE FROM BOILERS, STEAM GENERATORS AND PROCESS HEATERS IN PETROLEUM REFINERIES

Workshop Report
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1.0 Introduction

The Bay Area Air Quality Management District ("BAAQMD" or the "Air District") will hold a public workshop to discuss and solicit input on proposed amendments to Regulation 9, Rule 10: *Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries* ("Regulation 9-10" or "the rule"). In Further Study Measure 14 of the Bay Area 2005 Ozone Strategy, the Air District identified refinery boilers, steam generators and process heaters as a potential source of further reductions of emissions of nitrogen oxides (NOx), an ozone precursor. By reducing NOx emissions, the Air District would make progress toward meeting federal and state ozone standards, with respect to which the Air District currently is in nonattainment.

District staff recommends amending Regulation 9-10 by: (1) reducing NOx emissions limits for carbon monoxide (CO) boilers, one category of refinery boilers, steam generators, and process heaters that are currently regulated under the rule; and (2) modifying current exemptions. Current (2007) NOx emissions from refinery boilers, steam generators and process heaters (including CO boilers) that are subject to the rule are 12.4 tons per day. CO boilers had NOx emissions of 4.0 ton/day. The proposed amendments are expected to reduce total NOx emissions from refinery boilers, steam generators and process heaters by about 2.9 tons per day.

2.0 Background

Regulation 9-10 was adopted on January 5, 1994 and amended on July 17, 2002. The regulation imposes a refinery-wide average NOx emissions limit on refinery boilers, steam generators and process heaters (excluding CO boilers) that were permitted prior to the adoption of the rule ("pre-1994 heaters"). The NOx limits were not applied to boilers, steam generators and process heaters (except for CO boilers) that would be permitted after the rule was adopted ("post-1994 heaters") because these devices would be subject to stringent NOx limits as a result of the District's "best available control technology" (BACT) requirements. The rule also imposes a specific (not average) NOx emission limit on all CO boilers.

The NOx limits in Regulation 9-10 for pre-1994 heaters, combined with BACT requirements for post-1994 heaters, resulted in significant reductions in NOx emissions from Bay Area refinery operations beginning in 2002. Currently, 81% of the total rated capacity of refinery boilers, steam generators and process heaters in the Bay Area is equipped with NOx controls of some kind.

In the Bay Area 2005 Ozone Strategy, Further Study Measure FS 14, the Air District committed to study ways that the existing Regulation 9-10 emissions limits might be tightened to achieve further NOx emissions reductions. As explained in the Ozone Strategy, however, the Air District did not commit to continue evaluation of any measure if it was determined to be technically infeasible, not cost-effective or inappropriate for any other reason, nor did the Air District commit to move forward with a measure that was deemed feasible as a result of its further study, unless and until the Air District conducted a rulemaking process.

In carrying out Further Study Measure FS 14, District staff has completed the following:

- Compiled a precise inventory of refinery boilers, steam generators and process heaters;
- Determined the type, age, retrofit ability of, and the nature of the emissions from, these refinery boilers, steam generators and process heaters;
- Evaluated the cost effectiveness of retrofits and replacement technologies;
- Evaluated the contribution to emissions of the heaters that are currently exempt from Regulation 9-10;
- Compared the NOx emissions limits imposed by other air districts on refinery boilers, steam generators and process heaters;
- Compared NOx emissions from and control of non-refinery boilers of similar size that are in use in the District; and
- Consulted extensively with industry representatives regarding these analyses.

District staff's findings and recommendations are set out in this workshop report.

2.1 Refinery Heaters Overview

Boilers and steam generators are devices that heat or boil water, while process heaters (also called furnaces) heat process streams other than water or steam, including crude oil, to required processing temperatures. Most refinery heaters, over 80% by number, are classified as process heaters rather than boilers or steam generators. The term "heater" will be used in this report to refer to boilers, steam generators and process heaters that are subject to Regulation 9-10.

Heaters regulated by Regulation 9-10 use a variety of fuels. Natural gas and refinery gas (a gaseous by-product composed of a variety of hydrocarbon compounds) are the predominant fuels used at the Bay Area refineries, together accounting for over 95% of the NOx emissions from heaters. Most refinery heaters are permitted to use both natural gas and refinery gas fuels. Three refineries operate CO boilers that burn CO-rich off-gas from cracking or coking units in addition to natural gas and refinery gas.

As mentioned above, Regulation 9-10 imposes NOx emission limits on refinery boilers, steam generators and process heaters in two categories. The first category comprises refinery boilers, steam generators and process heaters (excluding CO boilers) that were permitted prior to the adoption of the rule ("pre-1994 heaters"). Under the current rule, NOx emissions from pre-1994 heaters at each refinery are aggregated and averaged, and the average emissions may not exceed 0.033 pounds of NOx per million BTU of actual heat input (0.033 lb/MM BTU, which is equivalent to 28 parts per million by volume [ppmv] of NOx at 3% excess oxygen), evaluated on a daily basis.

Refinery boilers, steam generators and process heaters (excluding CO boilers) that were permitted on or after January 5, 1994 ("post-1994 heaters") are not regulated by Regulation 9-10, but each heater in this category is subject to stringent NOx limits as a result of BACT requirements for new or modified devices.

The second category of refinery heaters that is regulated by Regulation 9-10 is CO boilers. Although the term "boiler" is generally used to describe a heater that produces steam, in Regulation 9-10 CO boilers are defined as heaters that process waste gas from catalytic cracking units (CCU) or coker units, whether or not they produce steam. CCU and coker waste gas contains high levels of CO, which is burned to CO_2 in CO boilers with the resulting heat used to produce steam or to heat process streams. In Regulation 9-10, CO boilers are regulated separately from pre-1994 heaters because their high operating temperatures and the more variable quality of their fuel cause them to operate at significantly higher NOx emission rates than other boilers and heaters. CO boilers are subject to the rule regardless of when they were first permitted.

A small number of devices that would otherwise fall into the category of a pre-1994 heater or CO boiler are exempt from the Regulation 9-10 emissions limits. These are discussed in detail in Section 3.3, *infra*.

In addition, Regulation 9-10 does not apply to the following types of sources that operate at refineries:

- Internal combustion (IC) engines or boilers that recover heat from IC engine exhaust gases while burning supplementary fuel. IC engine NOx emissions are subject to Regulation 9-8.
- Boilers that recover heat from gas turbine or IC engine exhaust gases while burning supplementary fuel. Gas turbine NOx emissions are subject to Regulation 9-9. No refinery boilers are used to recover waste heat from IC engine exhaust.

- Heaters processing H_2S flue gas in sulfur recovery plants or sulfuric acid manufacturing plants. These heaters are not regulated because they have either very low NOx emissions or no practical NOx control options.
- Flares. Flare operations are subject to Regulation 12-12.

2.2 Number, Size and Age of Bay Area Refinery Heaters

Table 1 shows the number of heaters that are currently operated by Bay Area refineries. The data are separated according to the size (capacity) and type of the heater. The vast majority of refinery heaters are pre-1994 heaters with a capacity equal to or greater than 20 MM BTU/hr.

Table 1 – Regulation 9-10 Heaters at Bay Area Refineries			
Capacity Range (MM BTU/hr)	**Pre-1994 Heaters Subject to Reg 9-10**	**CO Boilers Subject to Reg 9-10**	**Post-1994 Heaters Not Subject to Reg 9-10**
<10	6		
10 to <20	6		1
20 to <50	37		4
50 to <100	28		3
100 to <150	22		2
150 to <200	11	1	
200 to <250	19	3	2
250 to <500	18	1	2
500 to <1000	8	1	1
Total	**155**	**6** (*Note 1*)	**15**

Table 1 Notes:

(1) One Bay Area refinery has been issued an Air District Authority to Construct to replace two CO boilers with two larger units. These units are planned to go into service in 2010. Table 1 reflects currently operating CO boilers.

Original construction dates and subsequent modification dates are available for the refinery heaters that are operating in the Air District. Many refinery heaters at the Bay Area refineries are over 40 years old and the oldest are over 75 years old. Thus, even a 30 or 40-year old heater is not necessarily approaching the end of its service life and heater age is typically not the determining factor in assessing the potential for emission reductions or the cost-effectiveness of reductions. The most important factors in determining potential emission reductions are the heater NOx emission rate, the size of the heater, the utility of the heater (*e.g.*, the fraction of time it is operated as well as the fraction of full firing rate at which it is operated) and the type of NOx control already installed. Typically, larger heaters with higher emission rates and higher utility are the best candidates for further NOx control, especially if they have no NOx controls or a low level of NOx control such as basic low-NOx burners. Since the refineries have already implemented NOx controls to meet the current refinery average NOx limit (*see* Section 3.2, *infra*), the most cost-effective emission reductions have already been achieved, and the best candidates for NOx controls to meet a lower limit are not obvious. NOx control retrofit options for refinery heaters are discussed in detail in Section 3.1, and cost-effectiveness of these control options is discussed in Section 3.2, *infra*.

2.3 Emissions Inventory

When Regulation 9-10 was adopted in 1994, the typical refinery heater operated at a NOx emission rate of 100 ppmv to 140 ppmv (*Reference 18*), with higher emissions at CO boilers. Most of these existing heaters were old enough that they had not triggered the District's BACT requirements, which apply to devices installed or modified after 1982. In fact, almost all of these heaters operated without NOx controls of any kind. In 1994, total NOx emissions from these heaters were estimated to be about 31 ton/day, and adoption of the Regulation 9-10 limits in 1994 ("Phase 1" limits) was expected to result in a 21 ton/day reduction in NOx. However, it appears that emissions from these heaters may have been underestimated in 1994. The current emissions and emission rates for these heaters, as well as 1994 emission rate data, suggest that total 1994 NOx emissions were in fact about 40 ton/day and that implementation of Phase 1 NOx controls achieved a NOx reduction of about 26 ton/day, which represents about a 65% emission reduction.

Table 2 shows current refinery emissions at each of the five Bay Area refineries, based on permit data for 2007. The current total NOx emissions for heaters subject to Regulation 9-10 (*i.e.*, pre-1994 heaters and CO boilers) equal 12.0 ton/day. Post-1994 heaters that are not subject to the rule contribute another 0.4 ton/day of NOx emissions. As shown in Tables 2 and 3, post-1994 heaters account for about 9% of the permitted heater capacity, but only about 3% of the NOx emissions.

Table 2
2007 Refinery NOx Emissions – Boilers, Steam Generators & Process Heaters (ton/yr)

Refinery	Pre-1994 Heaters Subject to Reg 9-10	CO Boilers Subject to Reg 9-10	Post-1994 Heaters NOT Subject to Reg 9-10
Chevron	606	NA	4
Shell	749	619	117
ConocoPhillips	185	NA	20
Valero	779	600	14
Tesoro	587	266	1
Total (ton/yr)	**2906**	**1485**	**156**
Total (ton/day)	**8.0**	**4.0**	**0.4**

Greenhouse gas emissions at refinery heaters are estimated in Table 3 based on the rated heat input rate of the heaters, the typical heater utilization, and the CO_2 emission factor for refinery waste gas.

Table 3 – 2007 Refinery Greenhouse Gas Emissions, CO_2 (ton/day)			
	Pre-1994 Heaters, Excluding CO Boilers	**CO Boilers**	**Post-1994 Heaters**
Rated Input (MM BTU/hr)	23721	2623	2462
Actual Input (MM BTU/hr) (*Note 1*)	13047	1836	1354
CO2 Emissions, ton/day (*Note 2*)	**22000**	**3100**	**2300**

Table 3 Notes:

(1) Actual input is calculated assuming 55% utilization for non-CO boilers and 70% for CO boilers.

(2) Emissions based on CO2 GHG emission factor for natural gas fuel: 139 lb CO_2/thou ft^3 refinery gas, from 2008 BAAQMD GHG Inventory (Reference 13), assuming heat value of 1000 BTU / ft^3

2.4 Regulations at Other California Air Districts

There are 13 active petroleum refineries in California (*Reference 4*): five in the Bay Area, two in Bakersfield and six in the Los Angeles area. Thus, the BAAQMD, the San Joaquin Valley Unified APCD (SJVUAPCD) and the South Coast AQMD (SCAQMD) regulate all petroleum refining operations in the state.

The San Joaquin Valley Unified APCD regulates refinery heaters under two different rules. Rule 4306 is a conventional NOx control rule with different emission rate limits for different heater size ranges. The Rule 4306 limits are currently in effect and are no more stringent than the BAAQMD's Phase 1 requirement of 28 ppmv (0.033 lb/MM BTU) in Regulation 9-10 for heaters up to 110 MM BTU/hr. For larger heaters, the Rule 4306 limit of 5 ppmv (0.0062 lb/MM BTU) is significantly more stringent than the Phase 1 requirements: 9 ppmv or 6 ppmv (0.011 lb/MM BTU or 0.007 lb/MM BTU), depending on the size of the heater. Rule 4320 imposes future NOx limits for refinery heaters up to 110 MM BTU/hr that are also significantly more stringent than the Phase 1 requirements. Importantly, however, a refinery in the SJVUAPCD may elect to pay an annual emission fee rather than comply with these limits at any heaters. The amount of the annual emission fee is capped at $13,600 per ton of NOx emitted (the cost-effectiveness threshold for the Carl Moyer Incentive Program). By contrast, the Air District's preliminary calculations suggest that the anticipated cost of achieving further NOx reductions from pre-1994 heaters (not including CO boilers) at Bay Area refineries will be several orders of magnitude greater than this cap. Also, San Joaquin's refineries are significantly smaller than those in the Bay Area and total active refining capacity in San Joaquin is less than that at the smallest of the five Bay Area refineries (*Reference 19*). Given the difference in infrastructure between refineries in San Joaquin and the Bay Area, and the fee option for compliance with Rule 4320, the Air District does not consider the numerical limits contained in SJVUAPCD's rules to be appropriate for Bay Area operations.

Compared to San Joaquin, the refining infrastructure in the South Coast AQMD is more similar to that in the Bay Area. However, the SCAQMD regulatory structure for refinery heaters is different. The SCAQMD regulates NOx and SOx emissions at refineries under a voluntary regional cap-and-trade program called RECLAIM (SCAQMD Regulation XX). RECLAIM provides annual emission allocations of NOx or SOx at each facility in the RECLAIM program.

The allocations were originally based on pre-1993 throughput at each source and on an emission factor for the source type, and were typically reduced annually to meet air quality goals. If a RECLAIM facility's NOx emissions exceed its total NOx allocation, then it must either reduce emissions or purchase RECLAIM trading credits (RTCs) to make up the difference. RTCs are generated by facilities that have NOx emissions lower than their total NOx allocation and these facilities may sell their RTCs to other RECLAIM facilities. Importantly, the RECLAIM program incorporates a "backstop" measure (South Coast Rule 2015) that requires the South Coast AQMD to track the selling price of RTCs and that triggers a RECLAIM program review, and possible suspension of allocation reductions, if the 12-month average NOx RTC price exceeds $15,000 per ton. This mechanism effectively limits the average cost of RECLAIM compliance to $15,000 per ton of NOx, since a RECLAIM facility may opt to purchase RTCs to comply with allocation limits rather than apply emission controls. The average cost of RTCs has never exceeded $15,000 per ton, except during the "energy crisis" of 2000-2001 when power producers drove the price of some NOx RTCs to $120,000 per ton (*Reference 20*). This episode triggered the 2005 amendment of the RECLAIM program that added the $15,000 per ton backstop and restrictions on RECLAIM participation by power producers.

RECLAIM allocations and allocation reductions are implemented through SCAQMD Rule 2002. After year 2006, allocation reductions were based on emission inventory reduction targets, rather than on reduced source emission factors. SCAQMD Rule 2002 specifies additional allocation reductions through year 2011. No allocation reductions are specified after year 2011, although SCAQMD Rule 2002 includes a mechanism to mandate additional reductions if deemed necessary to meet air quality goals. Thus, current RECLAIM NOx allocations are based on NOx emission reduction goals, rather than on specified emission levels for heaters and other equipment. Nonetheless, the SCAQMD is required to show that emission reductions under RECLAIM are no less than would be obtained through the implementation of "best available retrofit control technology" (BARCT) with a conventional "command and control" rule structure. In order to make this showing, the SCAQMD made BARCT determinations for refinery heaters as part of the 2005 RECLAIM amendments (*Reference 20*), and committed to update BARCT determinations with every new AQMP update. The SCAQMD AQMP was updated in 2007, but the 2005 refinery heater BARCT determinations were not changed. These determinations are shown in Table 4.

Table 4 – South Coast AQMD NOx BARCT for Refinery Heaters

Input Heat Rating	**BARCT** (*Note 1*)	**SCAQMD Analysis**
5 to 40 MM BTU/hr	0.011 lb NOx / million BTU heat input (9 ppmv @ 3% O2)	ULNB retrofit is cost effective and achieved in practice.
>40 to 110 MM BTU/hr	0.030 lb NOx / million BTU heat input (25 ppmv @ 3% O2)	ULNB retrofit is cost effective and achieved in practice.
>110 MM BTU/hr	0.006 lb NOx / million BTU heat input (5 ppmv @ 3% O2)	SCR retrofit is cost effective and achieved in practice.
Fluid Catalytic Cracking Unit (FCCU)	≥85% emission reduction	≥85% reduction is cost effective and achieved in practice.

Table 4 Notes:

(1)BARCT for heaters from 5 to 40 MM BTU/hr input was established in the staff report for the 2008 amendment of SCAQMD Rule 1146 (Reference 21). All other BARCT determinations are from the 2005 RECLAIM amendments (Reference 20)

As Table 4 shows, the SCAQMD BARCT determination for heaters larger than 40 MM BTU/hr and up to 110 MM BTU/hr (25 ppmv @ 3% O2) is not significantly more restrictive than the current BAAQMD Regulation 9-10 average limit (28 ppmv @ 3% O2). However, SCAQMD has made BARCT determinations for refinery heaters up to 40 MM BTU/hr (9 ppmv) and for heaters larger than 110 MM BTU/hr (5 ppmv) that are significantly more restrictive than the current average emission limit in BAAQMD Regulation 9-10 (28 ppmv). The 5 ppmv BARCT emission rate for heaters larger than 110 MM BTU/hr is the same as the limit that the SJVUAPCD imposes on heaters in this size range under SJVUAPCD Rule 4306. In practice, these BARCT determinations are not applied as emission limits on refinery heaters because the heaters are instead subject to NOx allocation reductions based on NOx emission reduction goals. Still, Air District staff looked to the BARCT determinations for comparison purposes, since SCAQMD is required to demonstrate that the RECLAIM program is at least as effective as implementing the BARCT limits. As discussed above, however, SCAQMD Rule 2002 and the cap and trade mechanism effectively limits the average cost of NOx control to the average price of RTCs, which has not exceeded $15,000 per ton since the backstop provision went into effect. Meanwhile, BAAQMD's preliminary calculations suggest that the anticipated cost of achieving further NOx reductions from pre-1994 heaters (not including CO boilers) at Bay Area refineries will be several orders of magnitude greater than this amount. Thus, as with SJVUAPCD's limits, the Air District does not consider the SCAQMD's rules to be appropriate for Bay Area operations.

The SCAQMD BARCT determination for fluid catalytic cracking units (FCCUs) has the same purpose as the NOx limit for CO boilers in BAAQMD Regulation 9-10, since FCCU exhaust is routed to a CO boiler prior to discharge. The SCAQMD BARCT determination of 85% minimum emission reduction from FCCUs is significantly more stringent than the 50% minimum emission reduction for CO boilers in BAAQMD Regulation 9-10. Again, this BARCT determination is not applied as an emission limit on FCCU/CO boilers in the SCAQMD and NOx control costs are somewhat limited by the $15,000 per ton backstop mechanism. The Air District is examining the specific operating characteristics of Bay Area CO boilers to determine if the SCAQMD BARCT determination for FCCUs is applicable to the Bay Area CO boilers.

2.5 Comparison of Emissions at Refinery Heaters and Similar-Sized Non-Refinery Heaters

Non-refinery boilers, steam generators and process heaters are regulated by BAAQMD Regulation 9, Rule 7. These boilers, steam generators and process heaters contribute less NOx emissions than their refinery counterparts. In 2008, the District estimated the total NOx emissions from non-refinery heaters to be 5.1 ton/day (*Reference 11, Table 4*), whereas 2007 NOx emissions from refinery heaters that are regulated by Regulation 9-10 were approximately 12.0 ton/day (Table 2, *supra*).

Regulation 9-7 was amended in 2008 and will impose new NOx limits for non-refinery heaters in 2011 and 2012. The future NOx limits in Regulation 9-7 are summarized in Table 5.

Table 5
2011 / 2012 NOx Limits for Non-Refinery Heaters - Regulation 9-7

Rated Heat Input (MM BTU/hr)	NOx Limit (ppmv)
>2 to 5	30
>5 to <10	15
10 to <20	15
20 or more, load-following unit	15
20 to <75	9
75 or more	5

Almost all refinery heaters are larger than 5 MM BTU/hr, and would be subject to a future NOx limit of 15 ppmv (6% of refinery heaters), 9 ppmv (45% of refinery heaters) or 5 ppmv (49% of refinery heaters) if they were subject to Regulation 9-7. These are more stringent than the limits currently imposed on these heaters by Regulation 9-10 (approximately 28 ppmv for pre-1994 heaters, and 150 ppmv for CO boilers).

However, the population of heaters subject to Regulation 9-7 is very different than the one subject to Regulation 9-10. Almost all of the heaters that are subject to Regulation 9-7 are water boilers or low-pressure steam boilers that operate at relatively low temperatures and that use natural gas fuel exclusively. By contrast, over 80% of the heaters at refineries are process heaters rather than boilers. Process heaters typically burn refinery gas fuel, which has different properties than pipeline-quality natural gas fuel. Refinery gas composition varies among refineries, but in some cases the refinery gas has a significantly higher heat value than natural gas and therefore burns at a higher temperature, thus creating more NOx. Available low-NOx and ultra-low-NOx burners are designed and optimized to use pipeline-quality natural gas fuel exclusively, and the use of refinery gas fuel may increase NOx emissions by as much as 20% compared to natural gas (*Reference 18*). These factors make NOx control at most refinery heaters more challenging compared to the heaters regulated under Regulation 9-7. In 2005 the SCAQMD concluded that ultra-low-NOx burners, which can achieve NOx emission rates of as little as 9 ppmv in natural gas-fired boilers, were only capable of 25 ppmv performance in refinery heater applications “due to the size and design of the equipment and the combustion characteristics of refinery gas” (*Reference 20*). As discussed in Section 2.4, this finding has not been revised by SCAQMD.

For these reasons, District staff has determined that direct comparison of NOx emissions limits on non-refinery and refinery heaters is not appropriate and has not based the proposed amendments on Regulation 9-7 emissions limits. District staff invites comments on these issues.

3.0 Technical Review

3.1 Controlling Emissions

A refinery heater combustion process involves the combustion of a hydrocarbon fuel in the presence of oxygen (in the combustion air stream). The carbon in the fuel is oxidized to carbon dioxide (CO_2) and the hydrogen in the fuel becomes water vapor (H_2O). By-products of the process include: carbon monoxide (CO), nitrogen oxides (NOx), sulfur oxides (SOx), volatile organic compounds (VOCs), and particulate matter. NOx and VOC compounds react in the lower atmosphere to form ozone. NOx, SOx, VOCs, and ammonia may react to form fine particulate matter. NOx emissions that contribute to ozone formation are the focus of Regulation 9-10 and Further Study Measure FS 14.

3.1.1 NOx Emissions

The nitrogen contained in the NOx emissions from a refinery heater combustion process comes from one of two sources: (1) elemental nitrogen (N) that is chemically bound to the fuel molecules, and (2) nitrogen gas (N_2) that is part of the combustion air (air contains about 79% N_2 by volume). NOx formed from elemental, fuel-bound nitrogen is called "fuel NOx". Because natural gas and most other gaseous fuels have negligible levels of fuel-bound nitrogen, and because these are the primary fuels used in refinery heaters, fuel NOx is not a significant contributor to NOx emissions from refinery heaters. NOx formed from gaseous nitrogen that is introduced into the combustion process with the combustion air stream is the source of "thermal NOx" and "prompt NOx". Thermal NOx is created by a set of reactions that are affected primarily by heater temperature and excess O_2 concentration, with higher temperatures (especially greater than 2800ºF) and higher O_2 concentrations causing higher NOx generation rates. Prompt NOx is created by a set of reactions that are affected primarily by the air-fuel ratio in the combustion zone, with fuel-rich conditions promoting NOx formation. Thermal NOx is the primary component of NOx emissions from refinery heaters (*Reference 18*), although prompt NOx must be controlled to achieve overall NOx emission rates of 20 to 30 ppmv or less.

3.1.2 NOx Controls

Uncontrolled heaters use conventional burners that are not designed to achieve any particular level of NOx emissions. Conventional burners are designed to produce a small, hot flame by quickly and completely mixing fuel and combustion air. Such a flame allows the heater firebox to be as small as possible, and to be stable under a wide firing range and during fast changes in load.

The first level of control for a refinery heater is the use of low-NOx burners (LNB) which use staged-combustion techniques to suppress the formation of thermal NOx. Instead of mixing fuel and combustion air as quickly as possible, LNBs perform combustion in at least two stages, with the fuel-air ratio carefully controlled and the fuel and combustion air mixed thoroughly. Thorough mixing prevents combustion hot spots where NOx formation is high, while staged combustion produces a larger flame with a lower average temperature. Since the thermal NOx formation rate is highly dependent on combustion temperature, eliminating hot-spots and performing combustion at lower average temperatures reduces thermal NOx formation. Some refinery heaters continue to use conventional burners rather than LNBs because the firebox will not accommodate a larger flame. LNBs typically provide a 50% reduction of NOx formation compared to conventional burners. Implementation of the Phase 1 requirements of Regulation 9-10 resulted in an average refinery heater emission rate (excluding CO boilers) that was no higher than if all refinery heaters used this first level of NOx control.

Ultra-low-NOx burners (ULNB), in addition to suppressing thermal NOx formation, also suppress prompt NOx formation by avoiding fuel-rich conditions and reducing combustion temperatures. ULNBs use internal exhaust gas recirculation, where a portion of the combustion gases that are leaving the combustion zone are injected back into the combustion zone to cool the combustion temperature. ULNBs typically provide a 75% reduction of NOx formation compared to conventional burners.

Flue gas recirculation (FGR) reduces flame temperature by diverting some of the combustion exhaust gas back to the burner inlet, where it is mixed with the fuel and combustion air. Unlike the internal gas recirculation that occurs in ULNBs, FGR diverts exhaust gas outside of the firebox. The exhaust gas, while hot, is cooler than the combustion temperature, so FGR reduces the average flame temperature. The exhaust gas also has a reduced oxygen content compared to ambient combustion air, so the amount of excess oxygen available to form NOx is reduced. FGR may be used by itself or in combination with LNBs or ULNBs and typically will achieve an additional 10% reduction of NOx formation compared to LNBs or ULNBs by themselves. However, FGR imposes an efficiency penalty because it requires the use of an additional blower to recirculate exhaust gases.

A technique similar to FGR is the injection of water or steam into the combustion zone to lower combustion temperature. This technique is rarely used because it causes a large efficiency loss.

NOx emissions can also be reduced with add-on controls that convert previously-formed NOx to N_2 by reacting NOx with ammonia (NH_3), with or without the use of a catalyst. These post-combustion controls are known as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems, respectively. NOx catalysts operate well in a narrow temperature band, so SCR systems are less suitable in applications where a heater operates over a wide load range, which results in a wide temperature variation at the exhaust catalyst. SCR and SNCR systems can be costly to design, install and operate.

Compliance with the current NOx standards in Regulation 9-10 has been achieved through the use of LNBs, ULNBs and SCR at selected heaters. No new NOx control technologies have become available since the Phase 1 NOx controls in Regulation 9-10 were completely implemented in 2002. Although the performance of LNBs, ULNBs and SCR has improved somewhat since 2002, much of this improvement has been limited to natural gas-fired boilers. Also, there have been no breakthroughs that have resulted in lower costs for NOx emission controls or in significantly better NOx removal efficiency.

Bay Area refinery operators have a great deal of experience in the implementation of LNB, ULNB and SCR controls on boilers and process heaters. Much of the uncertainty about actual control performance that existed through the completion of Phase 1 controls in 2002 has been eliminated with respect to boilers and process heaters. However, because CO boilers are relatively few in number and because their operating conditions are very different from those of other heaters, the feasibility and effectiveness of NOx controls on CO boilers is not well understood and requires a case-by-case technical evaluation.

3.1.3 CO Emissions and Controls

Carbon monoxide is produced by the incomplete oxidation of carbon in a fossil fuel to CO rather than to CO_2. Because the Air District is in attainment status with all state ambient air quality standards for CO and is a "maintenance area" with respect to federal CO standards, Regulation 9-10 limits the concentration of CO in the exhaust stream of refinery heaters to a reasonable level (400 ppmv), but does not attempt to achieve further CO emission reductions. All other California air districts that address CO emissions from combustion sources impose the same 400 ppmv standard.

Burner-based NOx control strategies, which limit NOx formation by limiting combustion temperature, tend to also limit complete oxidation of carbon to CO_2, thereby increasing the CO formation rate. All refinery heaters, including CO boilers, may be operated at CO emission levels below 400 ppmv through good operating practice.

3.1.4 Greenhouse Gas Emissions and Controls

Combustion of conventional hydrocarbon fuel results in the release of energy in the form of heat as bonds between carbon and hydrogen are broken and reformed with oxygen to create water vapor (H_2O) and the greenhouse gas (GHG) carbon dioxide (CO_2). CO_2 is the only GHG emitted in significant quantities by refinery heaters. When methane (CH_4), the primary constituent of natural gas, is burned, the reaction proceeds as follows:

$$CH_4 + 2(O_2) \rightarrow CO_2 + 2(H_2O)$$

Thus, CO_2 is not a pollutant that occurs in relatively low concentrations as a by-product of the combustion process, like NOx; CO_2 is a necessary combustion product of any fuel containing carbon. The only practical way to reduce CO_2 emissions, and by far the least expensive way, is by increasing energy efficiency, *i.e.,* by consuming less fuel to provide the same useful energy output.

The current version of Regulation 9-10 has no GHG reduction or mitigation requirements. However, the California Air Resources Board (CARB) is implementing GHG reduction strategies as required by 2006 California Assembly Bill 32 (AB 32). The basic goal of AB 32 is to reduce California GHG emissions to 1990 levels by the year 2020. CARB intends to achieve this goal through several dozen individual measures. The measures most likely to affect Bay Area refineries are shown below. The first three measures are intended to directly reduce GHG emissions at refineries, while the last would reduce GHG emissions when refined transportation fuels are used. Indicated measure numbers are from the 2008 CARB AB 32 Scoping Plan.

- A regional GHG emission cap-and-trade program (C-11) is scheduled to be adopted in 2010 and implemented beginning in 2012.
- A measure (C-155) to reduce refinery flaring.

- A measure (C-156) to eliminate exemptions for methane emissions from refinery regulations.
- A low-carbon fuel standard (C-54) that calls for a reduction in the carbon-intensity of transportation fuels by 2020 to achieve about 10% of the overall AB 32 GHG reduction goal.

3.1.5 Potential Pollutant Trade-Offs

NOx controls have the potential to directly or indirectly cause emissions of other air pollutants or toxic emissions. Table 6 summarizes potential trade-offs for common NOx controls.

Table 6 – Potential Trade-Offs for Heater NOx Reductions

LNB, ULNB	• Replacing conventional burners with LNBs or ULNBs reduces heater efficiency because cooler combustion temperatures provide less radiant heat transfer. A loss of efficiency requires the heater to consume more fuel to achieve the same heating, thereby producing NOx and other combustion products. LNBs and ULNBs cause an efficiency loss through reduced radiant heat transfer of less than 1% of the heater output. • Installing LNBs or ULNBs may also cause an increase in CO emissions because, while lower combustion temperatures suppress the NOx formation reactions, they also suppress the full conversion of carbon in the fuel to CO_2, resulting in higher CO formation rates. However, proper design and operation should keep CO emissions under the current 400 ppmv limit.
LNB, ULNB + FGR	• FGR requires an external electric FGR blower that causes additional fuel consumption at the electricity source, which produces NOx and other combustion products. This efficiency penalty is typically less than 1% of the heater output. FGR cools the combustion zone even further than the LNB or ULNB, causing an additional loss of radiant heat transfer. However, because FGR increases the flow of hot gases through the heater, the convective heat transfer in the heater is increased, offsetting the reduction in radiant heat transfer. • Like LNBs and ULNBs, FGR promotes the formation of CO by cooling combustion temperatures. Proper design and operation should keep CO emissions under the current 400 ppmv limit.
LNB, ULNB + SCR	• SCR typically uses two electric SCR blowers that cause additional fuel consumption at the electricity source, which produces NOx and other combustion products. This penalty is typically less than 1% of the heater output. • SCR uses ammonia as a reducing agent in the reaction that converts NOx to N_2. Some of the ammonia does not react and escapes in the exhaust as "ammonia slip". Although ammonia is toxic, slip emissions typically do not result in a significant toxic risk. Ammonia is also a precursor to the formation of fine particulate matter compounds such as ammonium nitrate, as is NOx.

3.2 Potential for Further Reductions at Regulated Sources (Pre-1994 Heaters and All CO Boilers)

When Regulation 9-10 was adopted in 1994, the typical refinery heater operated at a NOx emission rate of 100 ppmv to 140 ppmv (*Reference 18*), with higher emissions at CO boilers. Most of these existing heaters were old enough that they had not triggered the District's BACT requirements, which apply to devices installed or modified after 1982. In fact, almost all of these heaters operated without NOx controls of any kind.

To comply with the "Phase 1" emissions limits adopted in Regulation 9-10 in 1994, each Bay Area refinery implemented extensive NOx controls on its respective population of pre-1994 heaters and on some CO boilers. By adopting a refinery-wide average limit for pre-1994 heaters, the District allowed each refinery the flexibility to decide the most cost-effective way for the refinery to comply. The unit-specific limit on CO boilers required that every CO boiler operate below the limit in the rule. As a result of these requirements, and because post-1994 heaters were subject to stringent BACT NOx control requirements, 81% of the total rated capacity (not the number of heaters) of refinery heaters (pre-1994 heaters, CO boilers and post-1994 heaters) currently are equipped with some level of NOx control. Table 7 shows the distribution of types of NOx controls on these heaters. Over 70% of the permitted heater capacity is controlled with either ULNBs or SCR and an additional 10% is controlled by LNBs. Only 19% of the permitted heater capacity currently has no NOx control.

Table 7 – NOx Control Distribution at Table 1 Heaters

NOx Control	Fraction of Total Rated Heater Capacity
No NOx Controls (conventional burners)	19%
Low-NOx Burners (LNB)	10%
Ultra-Low-NOx Burners (ULNB)	46%
Selective Catalytic Reduction (SCR)	25%

In carrying out Further Study Measure FS 14, District staff has considered requiring further NOx controls on pre-1994 heaters and CO boilers. For the reasons explained below, staff has determined that reducing the CO boiler NOx limit may be feasible. However, requiring further NOx controls on pre-1994 heaters at this time would not be cost effective in many cases. Staff proposes to continue to investigate the feasibility of reducing NOx emissions from pre-1994 heaters for future possible rule making. The Air District seeks comments on these findings and approaches.

3.2.1 Pre-1994 Heaters

Under current Regulation 9-19, pre-1994 heaters are subject to a daily average NOx limit of 0.033 lb/MM BTU of heat input. The refineries describe their efforts to comply with the Phase 1 limits for these heaters as follows:

- The Phase 1 NOx controls were applied in the most cost-effective way at each refinery, considering the specific advantages and disadvantages for LNBs, ULNBs and SCR at each heater. At each refinery the NOx controls that were implemented had a range of cost-effectiveness and it should be assumed that any additional NOx controls will be less cost-effective than the projects that have already been completed. Each refinery has provided an estimate of the cost-effectiveness for advanced NOx controls (ULNB and SCR) on each heater.

- Refinery operators sought to achieve the maximum NOx emission reduction from each Phase 1 control that was installed. Therefore, existing controls are unlikely to achieve any significant additional NOx reductions at low cost through optimization. Instead, any significant additional NOx reductions at an existing heater will require a complete control system design or re-design, procurement and installation of more advanced controls. Heaters that have no controls or a basic level of control (conventional burners or LNBs) typically have one or more factors (e.g. low rated fuel capacity, low annual utilization, internal or external space constraints) that make a higher level of control impractical or extremely expensive. Each refinery has provided a list of specific factors at each heater that negatively impact the cost-effectiveness of further NOx controls.

A review of cost data provided by the refineries has verified that, without considering constraints on the installation of NOx controls on specific heaters, the most cost-effective NOx emission reductions appear to be available on large heaters that currently use conventional burners with no NOx controls, or that use LNBs. For this sub-set of pre-1994 heaters, addition of either ULNBs or SCR would achieve significant cost-effective emission reductions. However, heater-specific constraints on the use of ULNBs or SCR may require that a heater be completely rebuilt or replaced, which significantly increase the cost of further emission reductions. These constraints may include:

- internal space constraints that preclude the use of ULNBs with their larger flame size;
- external space constraints that preclude the installation of an SCR system;
- high temperature conditions that limit the effectiveness of ULNBs; and
- low temperature conditions that limit the effectiveness of SCR.

Air District staff is continuing to evaluate the refineries' data regarding constraints at specific heaters to verify their validity. If the data are substantially verified, and further NOx controls on pre-1994 heaters are found to be not cost-effective, the current average limit would be retained. If, however, ULNBs or SCR may be installed and operated cost-effectively on some large heaters that are currently equipped with only conventional burners, then an adjustment to the current average NOx limit may be feasible.

3.2.2 CO Boilers

As shown in Table 1, six CO boilers are currently in operation at Bay Area refineries. CO boilers are used to burn process off-gas from catalytic cracking units (CCU) or coking units, or both.

Of the six CO boilers, one CO boiler has no NOx controls. Five use selective non-catalytic reduction (SNCR) systems to reduce NOx emissions. SNCR systems inject a nitrogen-containing reducing agent (urea or ammonia) into the boiler firebox, where the NOx compounds are converted to nitrogen gas (N_2) and water vapor. The SNCR reaction only occurs within the temperature range of about 1400°F to about 2000°F.

One refinery has been issued an Air District Authority to Construct to replace two CO boilers that currently use SNCR with new CO boilers that use more-effective SCR. This replacement will occur in 2010 or 2011. None of the CO boilers currently in operation uses SCR. SCR operates best within a limited temperature range, which is narrower and cooler than the SNCR temperature range. Where it is feasible to use, it is the single most effective type of NOx control (BAAQMD considers SCR best available control technology [BACT] for NOx).

The five CO boilers that use SNCR and the single CO boiler that has no NOx controls may have potential NOx reductions if SCR can be installed on these devices (or SNCR on the un-controlled CO boiler). Also, a hybrid technology has been demonstrated on a non-refinery boiler where an SCR system has been used downstream of an SNCR system.

Under current Regulation 9-10, the CO boilers are each subject to a 150 ppmv daily NOx limit. However, the Air District's data indicate that most of the CO boilers are capable of operating significantly below this limit when emissions are considered on an annual average basis. This has allowed the refineries to generate interchangeable emission reduction credits (IERCs) pursuant to District Regulation 2, Rule 9: *Interchangeable Emission Reduction Credits*. These IERCs have been used to offset excess emissions at other heaters, so that the overall control of NOx at refinery heaters has not been as extensive as it otherwise would have been. The use of IERCs is not improper. However, the ability of refinery operators to generate significant amounts of IERCs from CO boilers highlights the fact that a lower limit than 150 ppmv can be achieved on a long-term basis.

The proposed rule includes a tiered CO boiler NOx limit which retains the current 150 ppmv limit on a daily basis, but which adds lower NOx limits for 7-day and 365-day averaging periods, effectively reducing the allowed emissions on a long-term basis. The specific 7-day and 365-day limits are derived from BACT limits imposed in the Authority to Construct for the two planned, SCR-equipped CO boilers discussed above. As such, these proposed limits represent state-of-the-art NOx control. The Air District is continuing to evaluate the specific operating conditions at the four CO boilers that appear to have further emission-reduction potential and the costs of obtaining emission reductions and invites comments on the proposed limits.

3.3 Reductions from Currently Exempt Sources

As part of Further Study Measure 14, the Air District evaluated the contribution to emissions of the refinery heaters that are currently exempt from Regulation 9-10, to see if the contribution is significant and if requiring NOx emissions reductions from these heaters would be cost effective. However, District staff has found that the exempt heaters produced no or negligible NOx emissions and recommends that the current exemptions be retained (with a small modification to the exemption in Regulation 9-10-110.1, as explained below). District staff seeks comments on this approach.

The exempt refinery heaters fall into the following classes:

- Heaters that use exclusively natural gas and/or liquefied petroleum gas (LPG) fuel and that have a rated heat input less than 10 MM BTU/hr. (Regulation 9-10-110.1) There are a total of four heaters in this category with a total rated heat input of 22 MM BTU/hr. These heaters represent less than one-tenth of one percent of the total refinery heater rated input of 28,800 MM BTU/hr and therefore represent a negligible source of emissions. District staff proposes to narrow this exemption so that pre-1994 heaters with a rated heat input between 10 and 2 MMBTU/hr would be subject to the refinery-wide average NOx limit. District staff does not anticipate that the change will require any refinery to add NOx controls since the effect of adding these to the refinery-wide average will be negligible; however, it would make this exemption in Regulation 9-10-110.1 consistent with a similar exemption in Regulation 9-7-110.1.

- Heaters that use any fuel and that have a rated heat input less than 1 MM BTU/hr. (Regulation 9-10-110.2) These devices are not subject to any other regulation. There are no devices in this category at the five Bay Area refineries.

- Waste heat recovery boilers associated with turbines or IC engines. (Regulation 9-10-110.3) Each of the refineries operates at least one gas turbine that provides electrical power and steam and each turbine unit has one or more waste heat recovery boilers. Regulation 9, Rule 7, which applies to non-refinery boilers, includes the same exemption. Emissions from these boilers are not regulated because the fact that they recover heat that would otherwise be wasted is considered to be an environmental benefit that outweighs the NOx emissions produced by firing supplementary fuel in the boilers. Also, it is often impossible to measure the emissions from the boiler separately from those of the turbine, since they typically have a single exhaust stack, which complicates enforcement of a boiler NOx standard. Considering that waste heat recovery directly reduces GHG emissions, District staff recommends that waste heat recovery boilers remain exempt in Regulation 9-10.

- Heaters processing hydrogen sulfide process flue gas in sulfur recovery plants and their tail-gas treating units, or in sulfuric acid manufacturing plants. (Regulation 9-10-110.4) Each of the refineries operates a sulfur recovery plant with tail-gas treating units to comply with the requirements of District Regulation 9, Rule 1 to limit sulfur dioxide (SO_2) emissions. One of the refineries also operates a sulfuric acid manufacturing plant. The hydrogen sulfide gas (H_2S) that is processed at the sulfur recovery plants and sulfuric acid plant is a by-product of desulfurization processes that reduce the sulfur content of gasoline and diesel to meet state and federal fuel requirements. Both sulfur recovery plants and the sulfuric acid plant have a furnace where H_2S is burned with air. SO_2 emissions and emissions controls are well understood at both sulfur recovery units and sulfuric acid manufacturing plants. However, emission control guidance for these operations from U.S. EPA, the Air District and other sources is silent on the issue of NOx emissions and emission controls. Although standard NOx emission factors are not available for these operations, some source test data and other monitoring data are available for NOx from these operations. These data show that uncontrolled NOx emissions from these operations are typically lower than the current refinery-wide average NOx limit in Regulation 9-10. For this reason, District staff recommends retaining the existing exemption.

- Heaters fired on non-gaseous fuel when natural gas is unavailable for use. (Regulation 9-10-110.5) This exemption applies during a natural gas curtailment. Such a curtailment has never occurred in the Bay Area. All of the Bay Area refineries burn refinery gas fuel that is a by-product of refinery operations and use purchased natural gas for the balance of their fuel needs. In the event of a natural gas curtailment, refineries are unlikely to use non-gaseous fuels as a fuel substitute because most heaters are neither equipped nor allowed (by Air District operating permits) to use non-gaseous fuels, and instead the refineries would be forced to curtail or suspend operations. Because it has very limited potential effect on Bay Area emissions, District staff recommends retaining the existing exemption.

- Heaters with an actual heat input less than 90,000 therms each year. (Regulation 9-10-112) These devices are subject to tuning and monitoring requirements rather than a NOx emission limit. There are a total of five devices in this category at the Bay Area refineries. Because of their limited fuel use, emissions from these heaters are negligible. Accordingly, District staff recommends that these heaters remain exempt from emission limits.

4.0 Rule Amendments Under Consideration

At this time, District staff recommends amending Regulation 9-10 in two ways: (1) by adding more stringent limits on CO boilers; and (2) by narrowing one exemption, in Regulation 9-10-110.1, which would subject some currently exempt heaters to the rule's refinery-wide NOx limits.

First, as discussed above, since 1994, some CO boilers have demonstrated the ability to operate at significantly lower NOx levels than the current Regulation 9-10 limit of 150 ppmv. As a result, the Air District staff recommends amending Regulation 9-10 to impose more stringent NOx limits on CO boilers. Under the proposed rule, the current daily limit of 150 ppmv would still apply; however, more stringent weekly and annual (7-day and 365-day average, respectively) NOx limits on CO boilers would also apply. The new limits are shown in Table 8.

The 7-day and 365-day average NOx limits are based on the most recent (2009) BACT determination made for a CO boiler in the Bay Area. As discussed above, these limits are contained in the Authority to Construct for two planned, SCR-equipped CO boilers that are expected to begin operation at one of the Bay Area refineries in 2010 or 2011. They represent state-of-the-art NOx control.

Table 8 – Current and Proposed CO Boiler NOx Limits	
Current NO Limit (ppmv @ 3% oxygen)	**Proposed NOx Limits Effective 1/1/2015 (ppmv @ 3% oxygen)**
operating-day average: 150	operating-day average: 150
7-day average: none (*Note 1*)	7-day average: 85.6
365-day average: none (*Note 1*)	365-day average: 42.8

Table 8 Notes:

(1) Because the current rule has no explicit 7-day or 365-day NOx limits, CO boilers are allowed to operate at an average emission rate of as much as 150 ppmv on a daily or longer time basis.

The Air District recognizes that the specific numerical limits may need to be adjusted to reflect factors specific to some affected CO boilers that may preclude the use of, or reduce the effectiveness of SNCR controls, SCR controls or hybrid SNCR/SCR controls. The Air District is continuing to evaluate these factors and invites comments on its proposal to tighten NOx emissions limits on CO boilers; the numerical limits contained in the draft rule; and staff's proposed approach for refining the limits.

Second, the Air District proposes narrowing the exemption in Regulation 9-10-110.1 so that pre-1994 heaters with a rated heat input between 10 and 2 MMBTU/hr would be subject to the refinery-wide average NOx limit. As explained above, the Air District staff does not anticipate that the change will require any refinery to add NOx controls since emissions from these heaters is negligible; however, the change would make this exemption in Regulation 9-10-110.1 consistent with a similar exemption in Regulation 9-7-110.1. The Air District seeks comments on this proposed change.

District staff is not currently proposing further NOx emissions controls on pre-1994 heaters. However, staff proposes to continue investigating the feasibility of requiring further NOx controls on pre-1994 heaters for future possible rule making.

4.1 Potential Emission Reductions

As shown in Table 2, total NOx emissions from CO boiler emissions in 2007 were 4.0 ton/day. If it is assumed that all the CO boilers operate at the current 150 ppmv limit on an annual basis, and will reduce their emissions to the proposed limits, then emissions from CO boilers would be expected to be reduced by about 2.9 ton/day NOx.

4.2 Cost of Controls

The proposed changes to Regulation 9-10 may result in capital costs for NOx control equipment and may result in increased operating costs. Because the Air District already administers Regulation 9-10 and because the proposed amended rule will retain most of the same provisions, additional costs to the Air District will be limited to rule development costs, costs to process required compliance plans and permit applications for equipment modifications required by the propose amendments, as well as initial compliance verification costs.

4.2.1 Cost to Refinery Operators

Because refinery heaters, including CO boilers, are typically very large, any NOx reduction will require significant capital expenditure in the form of replacement low-NOx burners, upgraded or new SNCR, SCR or hybrid SNCR/SCR systems and associated upgrades of heater controls and ducting to accommodate these controls, and possibly complete heater replacement. Changing the CO boiler NOx limits, even if it does not require modifications to the CO boilers themselves, may require modifications to other heaters at a refinery that operates CO boilers. This is because, in some cases, refineries have used interchangeable emissions reduction credits (IERCs) rather than actual emission reductions to comply with the refinery-average NOx limit for pre-1994 heaters. These IERCs have been generated because CO boilers "over-comply" with the current 150 ppmv NO limit. If this limit were to be reduced and the level of "over-compliance" reduced, then the loss of IERCs may require that some non-CO boilers upgrade their NOx controls to remain in compliance with the refinery-average NOx limit.

The refinery trade group for the Bay Area – the Western States Petroleum Association (WSPA) – has contracted with engineering consultant ERM-West to inspect refinery heaters and analyze heater fuels and other factors to produce an accurate estimate of potential emission reductions and the associated cost-effectiveness for various NOx control technologies. WSPA has provided the results of this ongoing work to the Air District for review.

4.2.2 Cost to the Air District

In addition to the one-time cost of implementing the proposed amendments to Regulation 9-10, the Air District will also incur one-time costs to process permit applications for required heater modifications and to amend refinery Title V permits to reflect these modifications. Permit fees are expected to recover these permitting costs. Enforcement of the amended rule is not expected to result in significant new costs.

5.0 Rule Development / Public Consultation Process

The Air District has developed proposed amendments and presents these amendments in this workshop report. These proposals are based in part on existing regulations in other air districts in California. Staff has consulted with Bay Area refinery operators and with other California air districts during the preparation of this document.

The public workshop is the next step in the rule development process. The purpose of the workshop is to solicit comments from the public on the Air District's proposal to amend (or not amend, in the case of pre-1994 heaters) the NOx limits in Regulation 9-10. During the workshop, Air District staff will seek comments on issues discussed in this workshop report and will respond to questions about information set forth in this report. Staff will review and consider all comments received at the public workshop.

Staff is continuing to assess the refineries' submissions regarding potential emission reductions and associated retrofit costs for each heater and may consider changing other provisions in the rule beyond those proposed here. Should that be the case, staff will seek further public input prior to drafting a final proposal for consideration at a public hearing before the Air District's Board of Directors.

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