SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Staff Report

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

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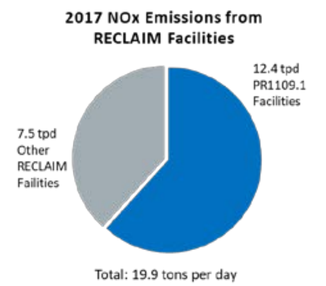
List of Acronyms

B-CAP	BARCT Equivalent Mass Cap Plan
B-PLAN	BARCT Equivalent Compliance Plan
BARCT	Best Available Retrofit Control Technology
CEMS	Continuous Emissions Monitoring System
CEQA	California Environmental Quality Act
CM	Control Measure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DCF	Discounted Cash Flow
DLN/DLE	Dry Low NOx/Dry Low Emissions
DOE	U.S. Department of Energy
ESP	Electrostatic Precipitator
°F	Degree Fahrenheit
FERCo	Fossil Energy Research Corporation
FCCU	Fluid Catalytic Cracking Unit
HAP	Hazardous Air Pollutant
HHV	High Heating Value of Fuel
HRSG	Heat Recovery Steam Generator
I-PLAN	Implementation Compliance Plan
GC/TCD	Gas Chromatograph-Thermal Conductivity Detector
LCF	Levelized Cash Flow
LNB	Low NOx Burner
LoTOx™	Low Temperature Oxidation Process for NOx Control
MMBtu	Metric Million British Thermal Unit
MMscf	Million Standard Cubic Feet
NAAQS	National Ambient Air Quality Standards
NEC	Norton Engineering Consultants Inc.
NG	Natural Gas
NH_3	Ammonia
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
O_2	Oxygen
PM2.5	Particulate Matter with diameter of 2.5 micrometers or smaller
PM10	Particulate Matter with diameter of 10 micrometers or smaller
ppmv	Parts Per Million by Volume
PR	Proposed Rule
PSA	Pressure Swing Adsorption
PWV	Present Worth Value
RECLAIM	Regional Clean Air Incentive Market Program
RFG	Refinery Fuel Gas
RTC	RECLAIM Trading Credit
South Coast AQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction

SIP	State Implementation Plan
SMR	Steam Methane Reformer
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOx	Sulfur Oxides
SRU/TG	Sulfur Recovery Unit /Tail Gas
SSM	Startup, Shutdown, and Malfunction
TIC	Total Installed Costs
tpd or TPD	Tons Per Day
ULNB	Ultra-Low NOx Burner
UltraCat^{TM}	UltraCat^{TM} Catalyst Filter Manufactured by Tri-Mer Corporation
U.S. EPA	U.S. Environmental Protection Agency
VOC	Volatile Organic Compound
WGM	Working Group Meeting
WHB	Waste Heat Boiler
WSPA	Western States Petroleum Association

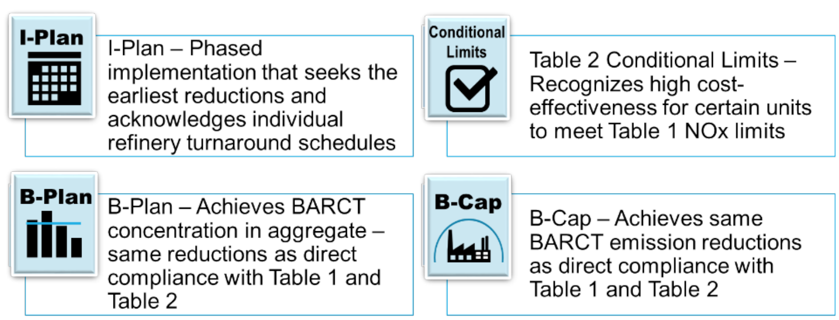
EXECUTIVE SUMMARY

Control Measure CMB-05 of the Final 2016 Air Quality Management Plan (AQMP) included a five tons per day Nitrogen Oxides (NOx) emission reduction as soon as feasible but no later than 2025, and directive to transition the REgional Clean Air Incentives Market (RECLAIM) program to a command-and control regulatory structure requiring Best Available Retrofit Control Technology (BARCT) as soon as practicable. California State Assembly Bill 617, approved by the Governor on July 26, 2017, requires air districts to develop, by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023 for facilities that are in the state greenhouse gas cap-and-trade program.



The REgional Clean Air Incentives Market (RECLAIM) program, which is under Regulation XX - RECLAIM –(Regulation XX), was adopted in October 1993 and is a market-based emissions trading program designed to reduce NOx and Sulfur Oxides (SOx) emissions. Petroleum refineries and facilities with related operations to petroleum refineries represent the largest source of NOx emissions in the RECLAIM program.

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) establishes NOx and Carbon Monoxide (CO) concentration limits that represent BARCT for combustion equipment located at sixteen petroleum refineries and facilities with operations related to petroleum refineries (e.g., sulfur recovery plants). The established BARCT NOx limits will require approximately 220 pieces of NOx equipment to be retrofitted with pollution controls which range from $10 million to $70 million per project, and $179 million to $1 billion per refinery. In addition, these complex projects require significant engineering, design, planning, logistics, funding, order/delivery, installation, and commissioning.



To address complexity of the pollution control projects, significant capital investments needed, need to minimize disruptions in fuel supply, and competition for the same resources, PR 1109.1 includes several compliance options: Conditional NOx limits for certain units that can meet specific conditions, an alternative implementation plan called an I-Plan, and two alternative BARCT emissions plans called a B-Plan and a B-Cap. Once fully implemented, PR 1109.1 is estimated to achieve approximately 7.7 to 7.9 tons per day of NOx emission reductions. It is expected that about 75 percent of the reductions would occur in 2027.

PR 1109.1 was developed through a public process that included 25 Working Group Meetings with nearly 100 meetings with environmental and community groups, CARB, U.S. EPA, individual facilities, and industry groups to gather direct input and help build consensus for the proposed rule.

CHAPTER 1 BACKGROUND

INTRODUCTION

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INTRODUCTION

The South Coast Air Quality Management District (South Coast AQMD) Governing Board adopted the Regional Clean Air Incentives Market (RECLAIM) program in October 1993. The purpose of RECLAIM was to reduce Nitrogen Oxides (NOx) and Sulfur Oxides (SOx) emissions through a market-based approach for facilities with NOx or SOx emissions greater than or equal to four tons per year. The program replaced a series of existing and future command-and-control rules and was designed to provide facilities with compliance flexibility. RECLAIM was designed to achieve emission reductions in aggregate equivalent to what would occur under a command-and-control regulatory approach. Regulation XX – REgional Clean Air Incentives Market (RECLAIM) (Regulation XX) includes a series of rules that specify the applicability and procedures for determining NOx and SOx facility emissions allocations, program requirements, as well as monitoring, reporting, and recordkeeping requirements for RECLAIM facilities.

In response to the growing concern that hundreds of units in RECLAIM are currently operating above NOx Best Available Retrofit Control Technology (BARCT) emission levels, Control Measure CMB-05 of the 2016 AQMP committed to identify approaches to make the program more effective in ensuring equivalency with command-and-control regulations implementing BARCT and to provide an assessment of the RECLAIM program in order to achieve further NOx emission reductions of five tons per day (tpd). During the adoption of the 2016 AQMP, the Resolution directed staff to modify Control Measure CMB-05 to achieve the five tons per day NOx emission reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring BARCT-level controls as soon as practicable.[1]

On July 26, 2017, California State Assembly Bill 617 – Nonvehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants (AB 617) was approved by the Governor, which addresses nonvehicular air pollution (criteria pollutants and toxic air contaminants). It is a companion legislation to Assembly Bill 398 – California Global Warming Solutions Act of 2006 (AB 398), which was also approved, and extends California's cap-and-trade program for reducing greenhouse gas emissions from stationary sources. RECLAIM facilities that are in the cap-and-trade program are subject to the requirements of AB 617. Requirements include an expedited schedule for implementing BARCT for cap-and-trade facilities and a requirement for the Air Districts throughout California to adopt an expedited BARCT schedule by January 1, 2019, to implement BARCT no later than December 31, 2023 by assigning the highest priority to those permitted units that have not modified emissions related permit conditions for the greatest period of time.

PR 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) will facilitate the transition of petroleum refineries and facilities with related operations to petroleum refineries to a command-and-control regulatory structure and partially implement Control Measure CMB-05 of the 2016 AQMP. Petroleum refineries and facilities with related operations to petroleum refineries are included in California's cap-and-trade program. PR 1109.1 applies to NOx emitting combustion equipment at facilities, including asphalt plants, biofuel plants, hydrogen production plants, petroleum refineries, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The proposed rule will establish NOx and Carbon Monoxide (CO) emission limits to reflect BARCT for most combustion

[1] http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2017/2017-apr7-001.pdf?sfvrsn=2

equipment categories at these facilities. Additionally, PR 1109.1 establishes provisions for monitoring, recordkeeping, and reporting and provides alternative implementation and compliance approaches including an Implementation Compliance Plan (I-Plan), BARCT Equivalent Compliance Plan (B-Plan), and BARCT Equivalent Mass Cap Plan (B-Cap).

REGULATORY BACKGROUND

Rule 1109 – Background

On November 1, 1985, South Coast AQMD adopted the Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries (Rule 1109). The rule was last amended on August 5, 1988. Rule 1109 was applicable to all boilers and process heaters in petroleum refineries and established a NOx refinery-wide emission limit of 0.14 lb/MMBtu (approximately 120 ppmv NOx corrected to three percent O_2) for the units operated on gaseous fuel, 0.308 lb/MMBtu (approximately 250 ppmv NOx corrected to three percent O_2) for the units operated on liquid fuel, and the weighted average of these limits for the units operated concurrently on both liquid and gaseous fuels when the units are firing at the maximum rated capacity. After December 31, 1995, the limit for gaseous fuels is reduced to 0.03 lb/MMBtu when firing on the maximum rated capacity. Rule 1109 includes provisions that the mass emissions cannot be greater than the mass emissions that are representative of 0.03 lb/MMBtu at the maximum rated capacity. In addition, Rule 1109 included an Alternative Emissions Control Plan that allowed an operator to submit a methodology that could provide equivalent emission reductions than the NOx standards in the rule. Since RECLAIM was adopted in 1993, the 1995 NOx standard of 0.03 lb/MMBtu was never implemented. No Alternative Emissions Control Plans were submitted and approved under Rule 1109.

RECLAIM Program

The RECLAIM program is a market-based program that was adopted in 1993 and applies to facilities with NOx and SOx annual emissions greater than or equal to four tons per year and is designed to achieve BARCT in aggregate. When the NOx RECLAIM program was adopted, facilities were issued an annual allocation of RECLAIM Trading Credits (RTCs), which declined annually from 1993 until 2003 and remained constant after 2003. At the end of each compliance year, facilities in the RECLAIM program must hold RTCs that are equal to or greater than the facility’s actual emissions. Under RECLAIM, facilities have the option to purchase RTCs, reduce throughput, implement process modifications, or install pollution controls to reduce emissions. RECLAIM is designed to achieve BARCT in aggregate. When RECLAIM was adopted, all petroleum refineries and facilities with operations related to petroleum facilities (related facilities) transitioned to this market-based program.

Pursuant to Health and Safety Code Section 40440 and 39616, South Coast AQMD is required to periodically assess the advancement in control technologies that are representative of BARCT to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach and that RECLAIM sources contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). Over the course of RECLAIM, there have been two BARCT reassessments for NOx in 2005 and 2015.

2005 NOx Shave

Assessment of actual NOx emission reductions as a result of the amendments to the NOx RECLAIM program in 2005 demonstrated that allowing for the use of shutdown RTCs in a market where many facilities have not yet installed BARCT controls can further delay or eliminate the need for facilities to install equipment to reduce their NOx emissions. The NOx RTC shave target for the 2005 amendments was 7.7 tons per day from 2007 to 2011. The actual NOx emission reductions between the timeframe of 2006 and 2012 was 4 tons per day. Of these 4 tons per day, 2.6 tons per day (or 65%) originated from facility shutdowns, while 1.4 tons per day (or 35%) came from either emission controls, process changes, or from a decrease in production levels due to the recession[2].

2015 NOx Shave

On December 4, 2015, Regulation XX was amended to reduce NOx allocations for the largest NOx emitters by 12 tons per day. Refineries and related industries represented approximately 7.9 tons per day (66 percent) of the 12 tons per day. The table below shows the NOx reduced levels for different combustion units under RECLAIM in 2005 and 2015 BARCT assessments and NOx shaves.

Table 1-1. 2005 and 2015 RECLAIM BARCT Levels

Unit	2005 NOx Level	2015 NOx Level	Oxygen Correction (%)
Fluid Catalytic Cracking Units	85% reduction	2 ppmv	3
Refinery Boilers and Process Heaters	5 ppmv	2 ppmv	3
Refinery Gas Turbines	N/A	2 ppmv	15
Petroleum Coke Calciner	30 ppmv	10 ppmv	3
Sulfur Recovery Units/Tail Gas Incinerators	N/A	2 ppmv	3

The intent of the BARCT reassessments was to ensure the RECLAIM program achieves BARCT in aggregate; however, evaluation of the units at petroleum refineries and related industries indicate 88 percent of the equipment at those facilities are not operating at levels representative of BARCT.

Implementation of the 2015 shave is designed to reduce NOx allocations by 12 tons per day from 2016 to 2022. The reduction in NOx allocations were greater towards the end of the shave period, with the greatest reductions occurring in 2022. Implementation of a shave does not necessary imply that a source will install pollution controls or reduce emissions as facilities under RECLAIM have the option to purchase RTCs. The 2015 NOx shave was expected to reduce NOx as follows:

- 2016: 2 tons per day
- 2017: 0 tons per day
- 2018: 1 ton per day
- 2019: 1 ton per day
- 2020: 2 tons per day
- 2021: 2 tons per day
- 2022: 4 tons per day

[2] http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2016/2016-Oct7-037.pdf?sfvrsn=9

2016 Regulation XX Amendments

During the 2015 rule development of Regulation XX to incorporate the 12 tons per day shave, concerns were raised that use of RTCs from shutdowns was contributing to the delay in installation of pollution controls. RECLAIM staff estimated that the shutdown of Cal Portland Cement allowed over 2 tons per day of RTCs to become available for sale and were subsequently purchased by other facilities to meet compliance obligations rather than installation of BARCT controls. To address RTCs from facility shutdowns, in October 2016, Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) (Rule 2002), which is one of the rules within Regulation XX, was amended to address the treatment of RTCs upon NOx RECLAIM facility shutdowns. The objective of the amendments was to prevent the RTCs associated with facility shutdowns from entering the market and delaying the installation of pollution controls at other NOx RECLAIM facilities. The amendments established the criteria for determining a facility shutdown (i.e., permanent or temporary) and the methodology to calculate the amount of reduction of future NOx RTCs holdings.

2018 Regulation XX Amendments

On January 5, 2018, the Board adopted amendments to Rules 2001 – Applicability (Rule 2001) and 2002. Amendments to Rule 2001 ended the addition of any facilities into RECLAIM, and Rule 2002 included provisions to establish the overall process to transition facilities from the RECLAIM program to a command-and-control regulatory structure. Before a facility can be transitioned out of RECLAIM, the facility must either have all equipment at BARCT or be subject to a rule that establishes BARCT requirements for all their equipment. Subsequently, U.S. EPA informed staff that RECLAIM facilities could not transition out of the program until the entire program had been amended and State Implementation Plan (SIP)-approved, so this provision was amended to not allow transitioning out of RECLAIM.

RECLAIM Emission Reductions

The RECLAIM program was designed to achieve BARCT in the aggregate and the intent of the BARCT reassessments was to ensure emission reductions were achieved that are equivalent to BARCT. However, evaluation of the units at petroleum refineries and related industries indicate 88 percent of the equipment at those facilities are not operating at levels representative of BARCT. As of August 2021, only 22 permits have been submitted from petroleum refineries and related industries for large NOx reduction projects (e.g., selective catalytic reduction (SCR) projects and low-NOx burners), compared to the 91 SCR projects assumed to be needed to achieve the NOx shave. Upon completion, those 22 projects will account for approximately 2.43 tons per day of NOx reduced. Further, 10 out of the approximately 100 boilers and process heaters 40 MMBtu/hour or greater are currently at or below 5 ppmv NOx or less.

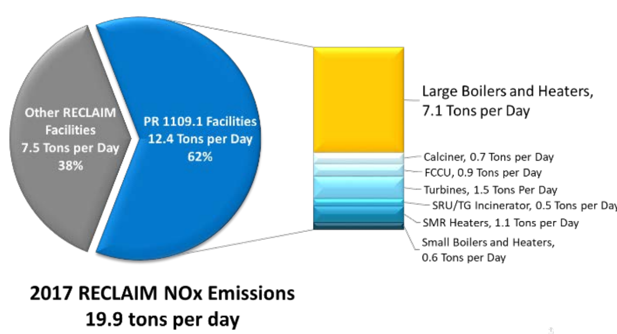


Figure 1. Percentage of NOx Emissions by Equipment Category

Figure 1-1 shows the percentage of emissions from each equipment category in Proposed Rule 1109.1. The highest emitting category of equipment at petroleum refineries and related facilities are process heaters and boilers that are rated at 40

MMBtu/hour or greater; this category accounts for approximately 58 percent of the total NOx emissions.

Figure 1-2 shows the NOx concentrations of boilers and heaters rated at or greater than 40 MMBtu/hour. Staff found that 95 percent of those units are currently not meeting a 5 ppmv or 2 ppmv NOx limits determined to represent the BARCT limits during the 2005 and 2015 RECLAIM BARCT assessment respectively.

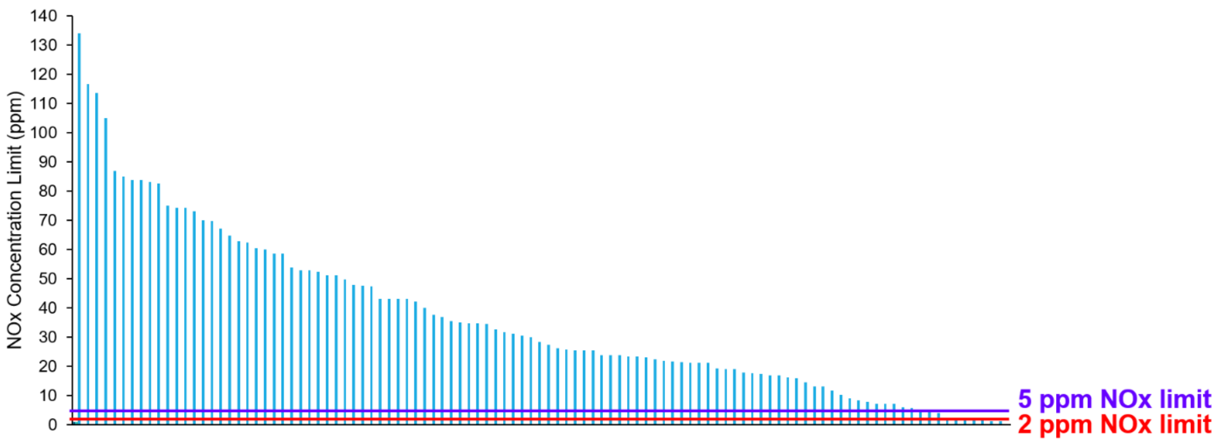


Figure 2. NOx Concentration Levels of Boilers and Heaters ≥40 MM Btu/hr

The trend of annual NOx emissions from the seven highest emitting refineries subject to PR 1109.1 since RECLAIM adoption in 1993 to 2019 is provided in the Figure 1-3. Estimated emissions in 1995 were higher than the ones in 1993 due to the prevalence of the use of missing data and difficulties associated with installation and certification of continuous emission monitoring systems (CEMS). Reported annual emissions decreased in the third compliance year due to the completion of CEMS installation and certification for most major sources. The emissions reported by CEMS are more accurate than emission factors used by facilities during the first compliance year or the missing data procedures used by many facilities during the second compliance year. Emission factors and missing data procedures tend to rely on conservative estimates or worst-case assumptions which could have overstated the emissions in the first two compliance years.

Refineries implemented emission reduction projects prior to 2001, however, in general emission reductions leveled off over the past 20 years[3].

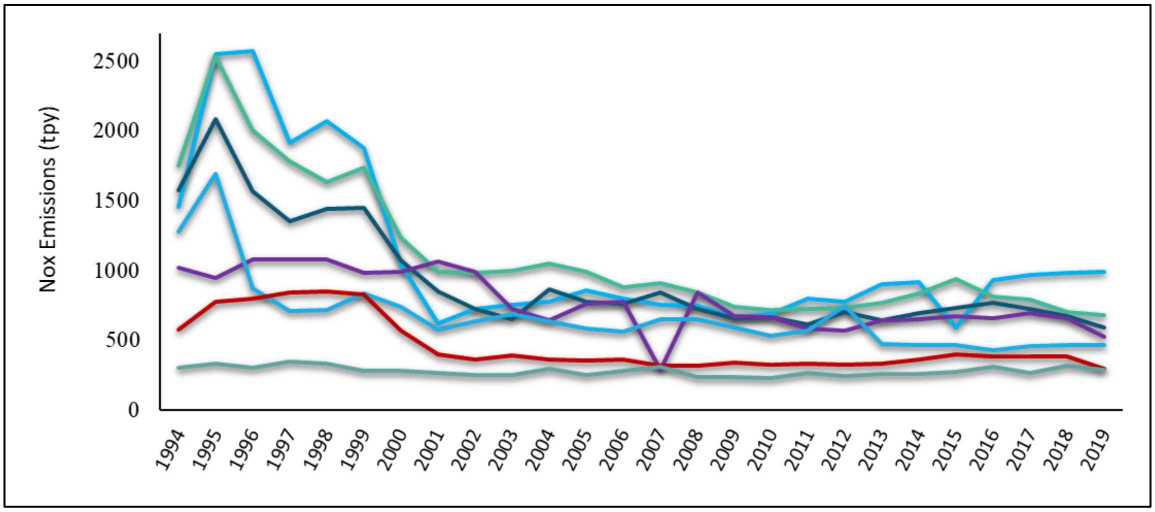


Figure 3. Trend of Annual NOx Emissions from Major Refineries

2016 Air Quality Management Plan (2016 AQMP)

The 2016 AQMP includes control measure CMB-05 which committed to identifying the approaches to make the RECLAIM program more effective. During the adoption of the 2016 AQMP, the Board approved a Resolution that directed staff to "modify the 2016 AQMP NOx measure (CMB-05) to achieve the five tons per day of NOx emission reduction commitment as soon as feasible, and no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring BARCT level controls as soon as practicable." To facilitate the transition of facilities from RECLAIM to a command-and-control regulatory structure, a "landing rule" is needed for each unit in RECLAIM. PR 1109.1 is one of fourteen landing rules that is needed for the RECLAIM transition and is in part implementing CMB-05.

AB 617: Nonvehicular Air Pollution – Criteria Air Pollutants and Toxic Air Contaminants

The adoption of AB 617 on July 26, 2017 by the California Legislature addressed facilities that are in cap-and-trade program and subject to the requirements of AB 617. Requirements include an expedited schedule for implementing BARCT for cap-and-trade facilities and a requirement for the Air Districts throughout California to adopt an expedited BARCT schedule by January 1, 2019 to implement BARCT no later than December 31, 2023 by assigning the highest priority to those permitted units that have not modified emissions related permit conditions for the greatest period of time. AB 617 requirements shall not apply to a unit that has implemented BARCT due to a permit revision or a new permit issuance since 2007.

PROPOSED RULE 1109.1

PR 1109.1 is necessary to achieve NOx reductions for the region to meet the state and federal air quality standards. Based on 2017 emissions data, staff estimates approximately 220 units are currently not operating at levels representative of BARCT. Potential NOx emission reductions from implementation of PR 1109.1 are substantial due to the size of the equipment, and the number

[3] http://www.aqmd.gov/docs/default-source/reclaim/reclaim-annual-report/1995-reclaim-report.pdf?sfvrsn=8

and magnitude of units operating above proposed BARCT levels. PR 1109.1 will in part implement CMB-05 by establishing NOx and CO limits that represent BARCT for combustion equipment at petroleum refineries and related facilities and will comply with AB 617 through implementing BARCT at facilities currently in the RECLAIM program. Under RECLAIM, facilities have the option to reduce emissions or to purchase RTCs to meet the annual compliance obligation to ensure that they hold RTCs equal to or greater than their emissions. PR 1109.1 facilities tend to purchase RTCs as their primary compliance option under RECLAIM and are currently holding 55 percent of the RTCs in the RECLAIM program. PR 1109.1 is a command-and-control rule that will require all units to meet NOx concentration limits either directly or in the aggregate.

Third Party Consultants

Staff contracted with two engineering consultants in May 2019: Fossil Energy Research Corporation (FERCo) and Norton Engineering Consultants Inc. (NEC) to provide technical review and input regarding the proposed BARCT NOx emission limits, cost estimates provided by refineries, and staff's approach and methodology to estimate costs where cost from refineries were not provided. Both consultants presented their findings and recommendations at the Working Group Meeting #16 and summarized their findings and recommendations in written reports which are included in Appendices B through G of this staff report.

Fossil Energy Research Corporation (FERCo)

FERCo has extensive knowledge and understanding of SCR as the predominate form of NOx control technology implemented at the local refineries. FERCo has a team of engineers that have robust experience in designing, engineering, and optimizing SCR systems in conjunction with vendors that have performed work for the local refineries. FERCo's design and engineering experience helped to evaluate site-specific issues at each facility. FERCo's engineering strength is also in SCR system optimization which qualifies this team to perform an analysis of existing SCR systems to determine whether further reductions can be achieved.

The FERCo contract was primarily to address the space constraints and challenges specific to petroleum refineries when installing NOx control equipment, in particular SCR installations. FERCo also assisted staff with the cost assessment. Staff and FERCo conducted several facility site visits to assess the availability of space for installation of NOx controls and discuss potential BARCT issues and concerns.

FERCo's statement of work (SOW) describes the tasks to include as follows:

- Perform site visits and engineering evaluation of the affected equipment (including, but not limited to, feasibility of installation of new controls or equipment);
- Consider any challenges associated with installation of control technologies, such as space constraints;
- Review installation challenges at multiple facilities and provide engineering design options when appropriate; and
- Conduct a feasibility study to determine if further optimization can be performed on currently installed NOx control systems to help achieve further reductions.

Norton Engineering Consultants Inc. (NEC)

Norton Engineering has a team of qualified engineers with technical experience in NOx control technologies and BARCT experience with refinery applications. Norton Engineering was contracted to review and conduct an independent review of staff's BARCT assessment. Staff relied on Norton Engineering to address technical questions and to provide their expertise on control technology and combustion equipment.

Norton Engineering's SOW describes the tasks to include as follows:

- Perform a technical feasibility assessment, including a review of commercially viable NOx control technologies and emission reduction levels that each technology can achieve, and any caveats associated with achieving the NOx reductions;
- Evaluate potential emissions of other air pollutants, including PM, ammonia, and CO, when implementing BARCT;
- Review and verify the initial costs that were submitted in 2018; and
- Analyze the modification and use of U.S. EPA SCR cost model, model input assumptions, local labor costs, and other factors that affect the cost-effectiveness calculation.

In March 2021, refineries submitted revised cost estimates. Staff extended the contract with Norton Engineering to provide a third-party review of the revised cost data submitted by refineries.

OTHER RELATED RULEMAKING

The figure below shows the other rule developments that will be required in conjunction with, or to support, PR 1109.1.

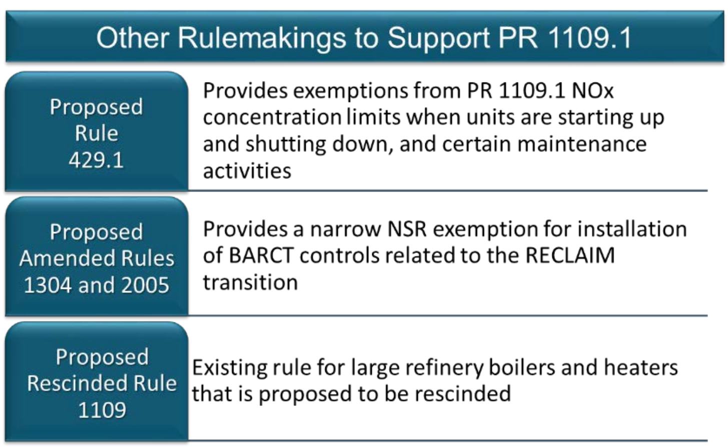


Figure 4. Other Related Rulemaking

Staff is proposing to rescind Rule 1109 when PR 1109.1 is considered for adoption. Since the adoption of RECLAIM, no facilities have been subject to Rule 1109. Proposed Amended Rule 1304 – Exemptions (PAR 1304) and Proposed Amended Rule 2005 – New Source Review for RECLAIM (PAR 2005) will implement a narrow (Best Available Control Technology) BACT exemption for PM and SOx emission increases associated with add-on air pollution control equipment installations or modifications at a RECLAIM or former RECLAIM facility to comply with a BARCT NOx standard. Lastly, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) will exempt equipment from the NOx and CO limits during period when the unit is starting up, shutting down, during certain catalyst maintenance activities, and commissioning, and limit the duration and frequency of those events for refineries and associated facilities that are subject to PR 1109.1. PR 429.1, and PARs 1304 and

2005 do not require any additional emission controls. For more information on PAR 1304, PAR 2005, and PR 429.1 please refer to the South Coast AQMD's website under Proposed Rules. Staff is also preparing Draft Staff Reports for these rulemakings that includes additional details regarding the proposals.

PUBLIC PROCESS

PR 1109.1 was developed through a public process that included a series of Working Group Meetings and one community meeting in the AB 617 community of Carson, Wilmington, and West Long Beach. Table 1-2 summarizes the Working Group Meetings held throughout the development of PR 1109.1 and provides a summary of the key topics discussed at each of the Working Group Meetings. Working Group Meetings ranged from one to five hours and included detailed presentations, which are posted on the South Coast AQMD's website[4]. Table 1-3 provides a summary of additional PR 1109.1 meetings.

Staff began the rule development process in the first quarter of 2018 and has conducted 24 Working Group Meetings to date. Staff will continue to conduct Working Group Meetings as well as individual stakeholder meetings as needed. The Working Group is composed of affected facilities, the Western States Petroleum Association (WSPA), consultants, equipment vendors, environmental and community groups, and other agencies such as the California Air Resources Board (CARB) and the U.S. EPA. The purpose of the Working Group Meetings is to work through the development of the proposed rule, discuss proposed rule concepts and identify and address key issues. The focal point of many of the Working Group Meetings was the BARCT assessment and the development of the proposed NOx limits for PR 1109.1. As a result of the impacts of COVID-19 and in accordance with the Governor's Executive Order N-29-20, all Working Group Meetings after March 18, 2020 were conducted remotely via video conferencing and teleconferencing.

Prior to the release of this Draft Staff Report and Draft Rule, seven versions of the draft proposed rule language were released to the public between October 2020 and October 2021. The initial version of the proposed rule language was released on October 23, 2020; the subsequent version released on November 20, 2020 included a subdivision with the alternative compliance options. A revised draft was released on December 24, 2020. One additional draft was released prior to the preliminary draft package, the pre-preliminary draft rule language version was released on July 21, 2021. The preliminary draft package was released on August 20, 2021 as part of the 75-day noticing of the Public Workshop, and two subsequent pre-30-day draft versions of the rule language were released on September 24, 2021 and October 4, 2021.

[4] http://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/proposed-rule-1109-1

Table 1-2. Summary of Working Group Meetings and Released Documents

Date	Meeting Title	Highlights
February 21,2018	Working Group Meeting #1	• Rule background • Potential universe • Equipment types and NOx emissions
June 14, 2018	Working Group Meeting #2	• Provided update on the survey questionnaire status (distribution, meeting with stakeholders, and revisions) • Revised universe and equipment • BARCT legal requirements and assessment approach • Emission data evaluation for all equipment categories
August 1, 2018	Working Group Meeting #3	• Progress of rule development • WSPA comments • First three steps of BARCT technology assessment
September 12, 2018	Working Group Meeting #4	• Presented the results from the fourth step of the technology assessment – "Assessment of Pollution Control Technology" for PR 1109.1 equipment • Presented emerging NOx control technologies • Control technologies and potential reductions
November 28, 2018	Working Group Meeting #5	• Analysis of the survey data submitted by the stakeholders • Methodology for data analysis for each of the seven source equipment categories • Low NOx burner/ultra-low NOx burner technologies
January 31, 2019	Working Group Meeting #6	• Updates and revisions to the survey data • Update on the Request for Proposal • Key takeaways from meetings with control technology vendors
April 30, 2019	Working Group Meeting #7	• NOx control technologies from meetings with manufacturers • BACT requirements due to equipment retrofit or replacement • U.S. EPA SCR Cost Model
June 27, 2019	Working Group Meeting #8	• Update on contracts with third-party consultants • CEMS data analysis • Methodology to determine operational peak • Modification to the U.S. EPA SCR Cost Model
December 12, 2019	Working Group Meeting #9	• NOx emission baseline • U.S. EPA SCR Cost Model modified with stakeholder costs • BARCT recommendations for the heaters and boilers • John Zink Combustions presented their new SOLEX burner technology for refinery heaters

Date	Meeting Title	Highlights
February 18, 2020	Working Group Meeting #10	• ClearSign Core™ burner project • Revised cost-effectiveness assessment for boilers and heaters • BARCT NOx limits for gas turbines, FCCUs, and SRU/TG incinerators • Internal combustion engines (ICEs) applicability in rule
Transitioned to Remote Participation via Zoom Video Conference Due to COVID-19		
May 21, 2020	Working Group Meeting #11	• Proposed BARCT NOx limits for the SMR heaters and ICEs • Proposed averaging times for boilers, process heaters, SMR heaters, gas turbines, FCCUs, SRU/TG Incinerators, and auxiliary ICEs
July 17, 2020	Working Group Meeting #12	• Follow-up on proposed BARCT NOx limits for ICEs • Proposed BARCT NOx limits for coke calciners and vapor incinerators • Response to the WSPA comment letter
August 12, 2020	Working Group Meeting #13	• Follow-up on SMR heaters BARCT assessment • BARCT NOx assessment for sulfuric acid plants (furnaces and startup heaters and boilers) • BARCT Evaluation of heaters and boilers with existing SCRs • Co-pollutants and sulfur clean-up in refinery fuel gas • Rule implementation concepts
August 27, 2020	Working Group Meeting #14 – Community Meeting with impacted communities of Carson, Wilmington, and West Long Beach	• Proposed BARCT NOx limits • Projected NOx emission reductions • Concepts for rule implementation • Request for equipment information for each refinery and the anticipated control technology by community representatives
October 23, 2020		Released First Version of PR 1109.1 Rule Language
November 4, 2020	Working Group Meeting #15	• Response to stakeholders' comments including updates to the BARCT assessments and rule language concepts • Rule implementation concept, BARCT-Compliance Alternative Plan (B-CAP)
November 20, 2020		Released Second Version of PR 1109.1 Rule Language with the B-Cap subdivision included

Date	Meeting Title	Highlights
December 10, 2020	Working Group Meeting #16 – Consultants presented Final Reports	• Revisions to CO and CEMS requirements • Updates to the implementation schedule • FERCo and Norton Engineering presentations • Revisions to PR 1109.1 based on feedback from FERCo and Norton Engineering
December 24, 2020		Released Third Version of PR 1109.1 Rule Language
February 4, 2021	Working Group Meeting #17	• Multiple SCR reactors • Rule language updates • Presentation by ClearSign™
February 11, 2021	Working Group Meeting #18	• Other related rulemaking projects • New approaches to achieve BARCT for large boilers and heaters • Review of BARCT and incremental cost-effectiveness assessments • Responses to submitted comment letters
March 4, 2021	Working Group Meeting #19	• Request for revised cost data • Proposed an updated NOx limit for large boilers and heaters (≥ 40 MMBtu/hr) • Reconsideration of FCCU and Vapor Incinerator BARCT assessment • Revised implementation schedule and approach with considerations for turnaround schedules • Introduced BARCT Equivalent Compliance Plan (B-Plan)
April 30, 2021	Working Group Meeting #20	• BARCT implementation and compliance plans • Proposed Rule 429.1 for startup and shutdown provisions at petroleum refineries • Presentation by ClearSign™ about combustion update
May 27, 2021	Working Group Meeting #21	• Introducing Bridge Concepts • Response to stakeholder's comment letters • Incremental Cost-Effectiveness Assessment • Alternative I-Plan Concepts • Gas Turbine and SMR Heater follow up
June 30, 2021	Working Group Meeting #22	• WSPA proposal and staff response • Facility provided updated costs and staff analysis • BARCT reassessment for large boilers and heaters and FCCUs • Initial concepts for mass emissions approach which was the revised B-Cap
July 14, 2021	Working Group Meeting #23	• Bridge limit considerations • PM/Co pollutant discussion

Date		Meeting Title	Highlights
			• BARCT reassessment for Vapor Incinerators • BARCT Equivalent Mass Cap (B-Cap) considerations
July 21, 2021			Fourth Version of PR 1109.1 Rule Language
July 28, 2021		Working Group Meeting #24	• BARCT reassessment for Vapor Incinerators • Discussion of July 21 version of Proposed Rule 1109.1
August 20, 2021			Release Preliminary Draft Rule and Staff Report
September 15, 2021		Working Group Meeting #25	• Discussed proposed changes to PR 1109.1, PR 429.1, and PAR 1304 • Discussed key issues
September 24, 2021			Release Pre-30-day Draft Rule
October 4, 2021			Release Revised Pre-30-day Draft Rule
October 6, 2021			Release Draft Rule and Staff Report

Table 1-3. Summary of Other Meetings

Date	Meeting Title
September 18, 2020	Stationary Source Committee Update
November 3, 2020 – November 6, 2020	CEQA meeting with all 16 Facilities
January 13, 2021 – September 24, 2021	Multiple B-Plan and I-Plan Meetings with all the 5 major petroleum refineries and the Environmental and Community Groups
February 19, 2021	Stationary Source Committee Update
September 1, 2021	Public Workshop
September 10, 2021	Study Session
September 17, 2021	Stationary Source Committee Update
October 1, 2021	Set Hearing

* Reference to B-CAP was changed later to the "B-Plan." In June staff introduced a new concept that was again referred to as a "B-Cap."

Throughout the rulemaking, staff has been meeting with individual stakeholders. In January 2021 staff initiated individual meetings with the five major petroleum refineries and environmental and community groups. Since January 2021, staff has held over 50 meetings with Chevron, Marathon (Tesoro Refinery), Phillips 66, Torrance Refining, and Valero. Since February 2021, staff held 15 meetings and met with representatives of Earth Justice, Coalition for Clean Air, Natural Resources Defense Council, and Communities for a Better Environment. In May 2021 after the WSPA proposed an alternative approach to PR 1109.1, staff began meeting weekly with WSPA and held ten meetings beginning May 20, 2021. Staff also met periodically, but on a less frequent basis with AltAir, World Oil, and Eco Services.

CHAPTER 2 BARCT ASSESSMENT

INTRODUCTION

Affected Facilities

PR 1109.1 will affect 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations.

Figure 5. PR 1109.1 Affected Facilities

PR 1109.1 will be applicable to 16 out of the 246 facilities in the NOx RECLAIM program as of October 2020; however, based on the 2017 RECLAIM Annual Emission Reports, these 16 facilities are responsible for 12.4 out of 19.9 tons per day of the NOx emissions.

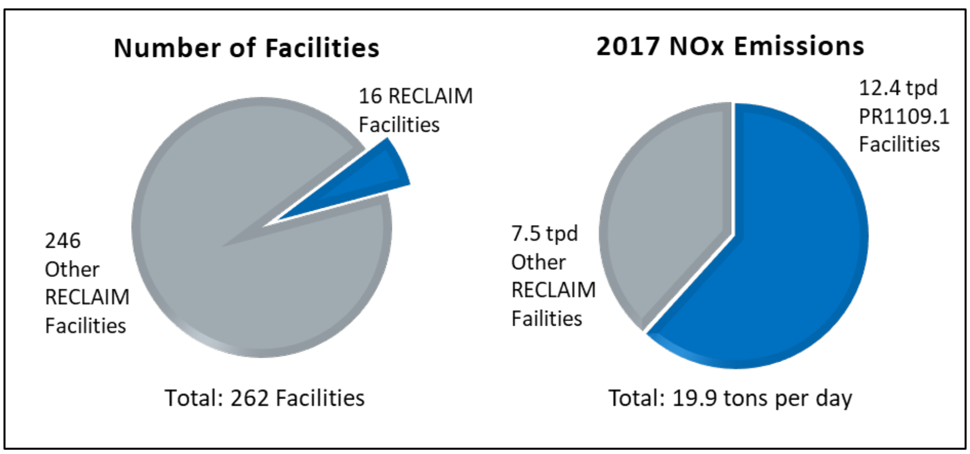


Figure 6. Number of Facilities and NOx Emissions PR 1109.1 versus RECLAIM

Affected Equipment

PR 1109.1 applies to nearly all combustion equipment at petroleum refineries and related facilities. Based on South Coast AQMD's permit database and facility surveys, staff has identified 284 units that will be subject to the PR 1109.1, with six major categories of equipment:

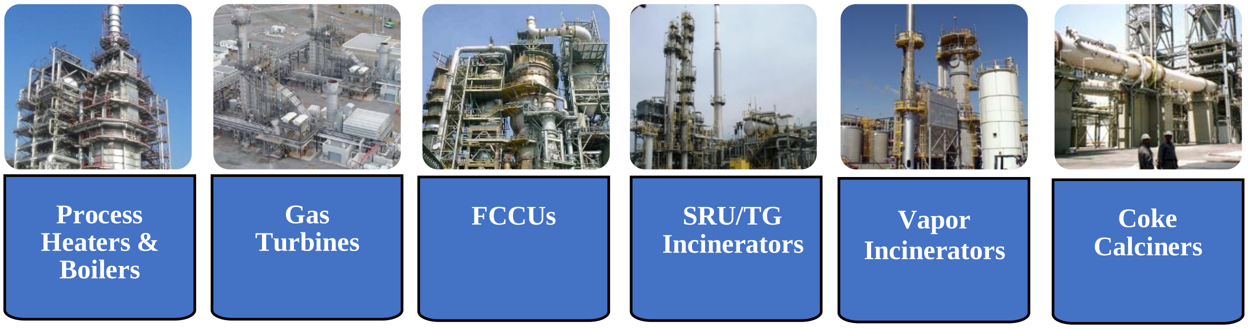


Figure 7. Major Categories of Equipment

Heaters and boilers are the largest equipment categories representing 80 percent of all equipment. There are many subcategories of equipment, especially in the process heater and boiler category which includes steam methane reformer (SMR) heaters, sulfuric acid plant furnaces, and startup heaters or boilers. The vapor incinerator category also includes several subsets including soil vapor extraction units, thermal oxidizers, and one small flare.

The table below summarizes the number of PR 1109.1 equipment at the 16 refineries and related facilities.

Table 2-1. PR 1109.1 Affected Equipment by Facility

	Process Heater/ SMR Heater/ Boiler	SRU/TG Incinerator	Vapor Incinerator	Gas Turbine	Start-Up Heater/ Boiler	FCCU	Coke Calciner	Flare
Tesoro-Carson	30	2	0	4	1	1	0	0
Tesoro-Wilmington	33	0	0	2	0	0	0	0
Tesoro-Sulfur Recovery Plant	0	2	0	0	0	0	0	0
Tesoro-Coke Calciner	0	0	0	0	0	0	1	0
Torrance	28	2	2	0	1	1	0	0
Chevron	37	4	5	4	1	1	0	0
P66-Carson	10	2	0	0	0	0	0	0
P66-Wilmington	34	2	0	1	2	1	0	0
Ultramar	19	1	0	1	1	1	0	0
AltAir	25	1	4	0	0	0	0	0
Lunday Thagard	5	0	2	0	0	0	0	0
Air Products-Carson	1	0	0	0	0	0	0	0
Air Products-Wilmington	1	0	0	0	0	0	0	0
Air Liquide	1	0	0	0	0	0	0	0
Eco-Services	0	0	0	0	2	0	0	1
Valero Asphalt Plant	4	0	0	0	0	0	0	0
Total	**228**	**16**	**13**	**12**	**8**	**5**	**1**	**1**

There are three source categories of combustion equipment at petroleum refineries and related facilities that are not included in PR 1109.1: refinery flares, small heaters used for comfort heating, and internal combustion engines (ICEs). These categories are regulated under existing South Coast AQMD rules. Details of exclusion are provided in the following sections for each category.

Refinery Flares

Refinery flares that are used exclusively to burn excess hydrocarbon gases are excluded from RECLAIM and will also be excluded from PR 1109.1. Those flares are currently regulated under Rule 1118 – Control of Emissions from Refinery Flares. Two types of flares are generally operated at refineries: elevated flares and flares, usually defined by the height of the flare tip above ground.

However, there is a small flare used at one of the facilities with related operation to petroleum refineries for plant activities such as tank degassing and truck unloading that is subject to PR 1109.1. The BARCT assessment for that unit is discussed later in this chapter and in Appendix G.

Small Heaters

Refinery boilers and heaters used in the petroleum refining process are all greater than 2 MMBtu per hour. Small heaters (less than or equal to 2 MMBtu per hour) used for comfort heating that are not used in refinery processing operations, are not subject to PR 1109.1. Small natural gas-fired water heaters, boilers, and process heaters (less than or equal to 2 MMBtu/hr) at PR 1109.1 facilities will be regulated under Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2). Units regulated under Rule 1146.2 are small and generally used for large water heaters and do not include units within the operating process of the refinery.

Internal Combustion Engines

There are three diesel ICEs at facilities within the PR 1109.1 universe that are used to power gas turbines during startup only. All these ICEs are low-use (less than 13 hours per year) engines with NOx emissions less than 0.001 ton per day. A BARCT assessment for these units was conducted and presented during the Working Group Meeting #11 held on May 21, 2020 and a follow-up assessment was presented during Working Group Meeting #12 held on July 17, 2020. SCR was determined to be the best retrofit control technology to reduce NOx; however, because these ICEs are only used for short time periods during the start-up of gas turbines, they would not reach the minimal temperature required for the SCR to reduce NOx. Staff evaluated ICE replacement to achieve significant NOx reductions. Based on the NOx limits in Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (Rule 1110.2), staff evaluated an 11 ppmv NOx limit, as required for stationary ICE, as well as a 36 ppmv NOx limit, as allowed for low-use ICE (less than 500 hours/year). The BARCT assessment demonstrated that meeting a NOx emission limit of 11 ppmv or 36 ppmv was not cost-effective and would have technical challenges. Staff considered including a low-use exemption in PR 1109.1 (i.e., operating for ≤100 hours per year) and establishing NOx limits and requirements if the unit exceeds the annual operating hour exemption. However, staff determined the best path forward for these low-use ICEs was to allow them to be subject to Rule 1110.2 which has a provision under subparagraph (i)(1)(E) for auxiliary engines used to power other engines or gas turbines during startups.

BARCT ASSESSMENT APPROACH

The purpose of a BARCT assessment is to assess available pollution controls to establish emission limits for specific equipment categories consistent with the state law. Under California Health and Safety Code Section 40406, BARCT is defined as:

> "an emission limitation that is based on the maximum degree of reduction achievable by each class or category of source, taking into account environmental, energy, and economic impacts."

The BARCT assessment follows a framework through the rule development process and includes public participation. The figure below shows the BARCT assessment approach. A summary of the BARCT assessment is provided in this chapter. A complete BARCT assessment for each class or category is presented in Appendices B through G.

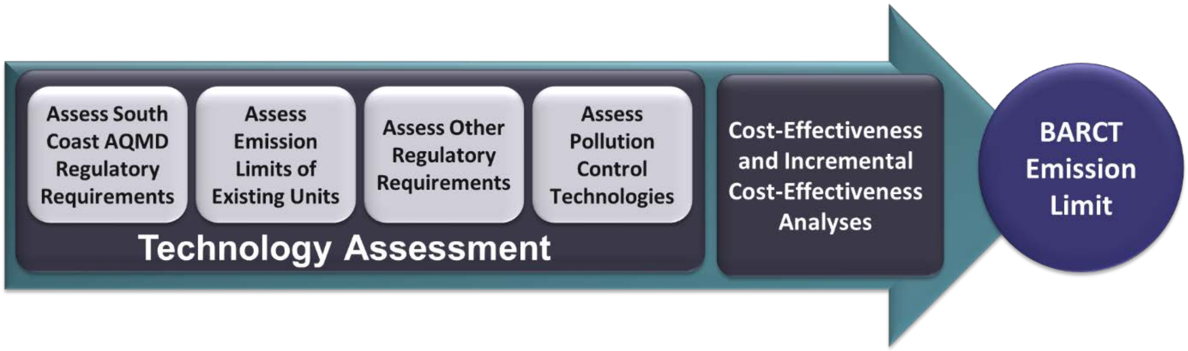


Figure 8. BARCT Assessment Approach

The scope of BARCT including Retrofit Versus Replacement, Emerging Technology, and Class and Category Determination

During the rule development of command-and-control rules for the RECLAIM transition, industry stakeholders commented on the scope of "best available retrofit control technology" relative to Health & Safety Code § 40440(b)(1). A commenter stated that the use of the word "retrofit" precludes the South Coast AQMD from requiring emissions limits that can only be cost-effectively met by replacing the basic equipment with new equipment. Staff believes that the use of the term "retrofit" does not preclude replacement technology.

The on-line Merriam-Webster Dictionary defines "retrofit" in a manner that does not preclude replacing equipment. That dictionary establishes the following definition for retrofit: "1) to furnish (something, such as a computer, airplane, or building) with new or modified parts or equipment not available or considered necessary at the time of manufacture, 2) to install (new or modified parts or equipment) in something previously manufactured or constructed, 3) to adapt to a new purpose or need: modify." https://www.merriam-webster.com/dictionary/retrofit. This definition does not preclude the use of replacement parts as a retrofit.

The on-line Dictionary.com is more explicit in allowing replacement parts. It includes the following definitions for retrofit as a verb: "1. to modify equipment (in airplanes, automobiles, a factory, etc.) that is already in service using parts developed or made available after the time of original manufacture, 2. to install, fit, or adapt (a device or system) or use with something older; to retrofit solar heating to a poorly insulated house, 3. (of new or modified parts, equipment, etc.) to fit into or onto existing equipment, 4. to replace existing parts, equipment, etc., with updated parts or systems." http://www.dictionary.com/browse/retrofit. This definition clearly includes replacement of existing equipment within the concept of "retrofit." Accordingly, the use of the term "retrofit" can include the concept of replacing existing equipment.

Moreover, the statutory definition of "best available retrofit control technology" does not preclude replacing existing equipment with new cleaner equipment. Health & Safety Code § 40406 provides: "As used in this chapter, 'best available retrofit control technology' means an emission limitation that is based on the maximum degree of emission reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source." Thus, BARCT is an emissions limitation, and is not limited to a particular technology, whether add-on or replacement. Certainly, this definition does not preclude replacement technologies.

Staff also notes that the argument precluding replacement equipment would have an effect contrary to the purposes of BARCT. For example, staff has proposed, and the Board adopted in Rule 1135 a BARCT that may be more cost-effectively be met for diesel-fueled engines by replacing the engine with a new Tier IV diesel engine rather than installing additional add-on controls on the current engine which may be many decades old. If the South Coast AQMD were precluded from setting BARCT for these sources, the oldest and dirtiest equipment could continue operating for possibly many more years, even though it would be cost-effective and otherwise reasonable to replace those engines. There is no policy reason for insisting that replacement equipment cannot be an element of BARCT as long as it meets the requirements of the statute including cost-effectiveness.

The case law supports an expansive reading of BARCT. In explaining the meaning of BARCT, the California Supreme Court held that BARCT is a "technology-forcing standard designed to compel the development of new technologies to meet public health goals." (*American Coatings Ass'n. v. South Coast Air Quality Mgt. Dist.*, 54 Cal. 4th 446, 465, 2012). In fact, the BARCT requirement was placed in state law for the South Coast AQMD in order to "encourage more aggressive improvements in air quality" and was designed to augment rather than restrain the South Coast AQMD's regulatory power (*American Coatings, supra*, 54 Cal. 4th 446, 466). Accordingly, BARCT may actually be more stringent than BACT, because BACT must be implemented today by a source receiving a permit today, whereas BARCT may, if so, specified by the South Coast AQMD, be implemented a number of years in the future after technology has been further developed (*American Coatings, supra,* 54 Cal. 4th 446, 467).

The Supreme Court further held that when challenging the South Coast AQMD's determination of the scope of a "class or category of source" to which a BARCT standard applies, the challenger must show that the South Coast AQMD's determination is "arbitrary, capricious, or irrational." (*American Coatings, supra,* 54 Cal. 4th 446, 474). Therefore, the South Coast AQMD may consider a variety of factors in determining which sources must meet specific BARCT emissions level. If, for example, some sources could not cost-effectively reduce their emissions further because their emissions are already low, these sources can be excluded from the category of sources that must meet a particular BACT. Therefore, the South Coast AQMD may establish a BARCT emissions level that can cost-effectively be met by replacing existing equipment rather than installing add-on controls, and the South Coast AQMD's definition of the category of sources which must meet a particular BARCT is within the South Coast AQMD's discretion as long as it is not arbitrary or irrational.

Emerging Technology

The BARCT emission levels can also be technology forcing NOx concentration limits, meaning the limits can be based on emerging technology provided the NOx limit is achievable by the compliance date. Emerging technology is technology that can achieve emission reductions but is not widely available at the time the NOx limit is established and the rule is adopted. When South Coast AQMD adopts rules with technology forcing emission limits, the limits are given a future implementation date to allow time for the technology to develop. BARCT limits evolve over time as technology improves or new pollution control technologies emerge; setting future effective emission limits is appropriate and the approach has been used, and upheld, in other rules. South Coast AQMD adopted volatile organic compound (VOC) limits in Rule 1113 – Architectural Coatings in 2002 with a future effective date of July 1, 2006, based on emerging technology (e.g., reformulated coatings). The technology to meet the lower VOC limits was commercially available but had performance issues that had yet to be overcome. The American Coatings Association sued the South Coast AQMD for adopting technology forcing BARCT limits, but the South Coast

AQMD prevailed in the Supreme Court of California upholding the ability to adopt technology forcing BARCT limits.

Class and Category of Equipment

One of the first steps in the BARCT assessment is to establish the class and category of equipment. Staff collaborated with the stakeholders to establish the class and category by accounting for the type of equipment, size, fuel type, and other unique operational features of the units. The following table lists the initial class and category of equipment established for the BARCT assessment of the equipment subject to PR 1109.1. Based on the BARCT technology assessment, the only category that has been distinguished by fuel type is the Gas Turbine category and the fuel type is included in the table for other categories for informational purposes. Renewable fuel gas listed in the following table is the gas generated at a biofuel plant.

Table 2-2. Class and Category of Equipment

Equipment Category	Size (MMBtu/hour)	Fuel Type
Boilers	<20	Refinery Fuel Gas, Natural Gas
	≥20 – <40	
	≥40 – ≤110	
	>110	
Flares	All	Natural Gas
FCCUs	All	Coke Burn-Off
FCCU Startup Heaters	All	Refinery Fuel Gas, Natural Gas, Ultra-Low-Sulfur Diesel
Gas Turbines Fueled with Natural Gas	All	Natural Gas
Gas Turbines Fueled with Gaseous Fuel other than Natural Gas	All	Refinery Fuel Gas, Other Process Gas, Propane, Butane, Other Gaseous Fuels
Petroleum Coke Calciners	All	Natural Gas
Process Heaters	<20	Refinery Fuel Gas, Natural Gas, Renewable Fuel Gas
	≥20 – <40	
	≥40 – ≤110	
	>110	
SRU/TG Incinerators	All	Refinery Fuel Gas, Natural Gas, Tail Gas, Renewable Fuel Gas
SMR Heaters	All	PSA-Off Gas, Refinery Fuel Gas, Natural Gas
SMR Heaters with Gas Turbine	All	PSA-Off Gas, Natural Gas
Sulfuric Acid Furnaces	All	Refinery Fuel Gas, Natural Gas, Hydrogen Sulfide
Sulfuric Acid Startup Heaters	All	Natural Gas
Sulfuric Acid Startup Boilers	All	Natural Gas
Vapor Incinerators	All	Refinery Fuel Gas, Natural Gas, Renewable Fuel Gas

Technology Assessment

Staff conducted a thorough technology assessment to evaluate the NOx control technologies that will achieve the BARCT level for combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries subject to PR 1109.1. The technology assessment consists of four steps including the assessment of South Coast AQMD requirements, a complete assessment of emission limits of existing units, review of other regulatory requirements, and assessment of available pollution control technologies.

Assess South Coast AQMD Regulatory Requirements

Assessment of South Coast AQMD Regulatory Requirements

Staff reviewed existing South Coast AQMD NOx regulations from combustion equipment at petroleum refineries and facilities with related operations. The combustion equipment within the refining sector consists of six main source categories previously discussed (see Figure 2-3). In addition, staff evaluated the South Coast AQMD NOx regulations for combustion equipment in non-refinery settings to assess potential technology transfer. This includes the evaluation of rules and regulations affecting equipment categories that will be regulated under PR 1109.1 (e.g., boilers and process heaters). The technology assessment includes a review of existing South Coast AQMD regulations to determine if NOx limits have been established for similar types of equipment that should be considered for PR 1109.1. In addition to the NOx rules, staff also evaluated the BARCT assessments which were previously conducted in 2005 and 2015 as part of the RECLAIM program to reduce facility's allocations. The following table summarizes the South Coast AQMD NOx rules that staff evaluated as part of the BARCT technology assessment.

Table 2-3. South Coast AQMD Regulatory Requirements

Regulation/Rule Title	Relevant Unit/Equipment	Fuel Type
RECLAIM BARCT (2005)	Refinery Boilers and Process Heaters, Petroleum Coke Calciners, FCCUs, Gas Turbines	See Table 2-2
RECLAIM BARCT (2015)	Refinery Boilers and Process Heaters, Petroleum Coke Calciners, FCCUs, Gas Turbines, SRU/TG Incinerators	See Table 2-2
Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines	Stationary and Portable Engines	Gaseous Fuels, Liquid Fuels
Rule 1118.1 – Control of Emissions from Non-Refinery Flares	Non-Refinery Flares	Landfill Gas, Digester Gas, Process Gas, VOC Off-Gas
Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines	Gas Turbines	Gaseous Fuels, Liquid Fuels
Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters	Boilers and Process Heaters	Gaseous Fuels, Non-Gaseous Fuels, Landfill Gas, Digester Gas
Rule 1147 – NOx Reductions from Miscellaneous Sources	Incinerators, Afterburners, Remediation Units, Thermal Oxidizers, Calciners/Kilns	Gaseous Fuels, Liquid Fuels

Assessment of Emission Limits of Existing Units

This step of the BARCT assessment highlights the emissions levels that can be achieved for the existing units in the different categories of equipment. To conduct this assessment, staff evaluated the current emissions and NOx concentrations of the existing units in the PR 1109.1 universe. Data on existing units include South Coast AQMD data such as permit limits, source test data, CEMS, and annual emission reports as well as the comprehensive data which staff received through the facility surveys. Summaries of the emission levels being achieved on equipment for each class and category in the PR 1109.1 universe are included later in this chapter, with detailed information discussed later in the appendices.

Other Regulatory Requirements

The next step of the technology assessment is to identify other agencies that regulate the same or similar equipment and compare the regulatory requirements and emissions limits. The purpose of this step is to evaluate if there are applicable emissions limits that should be considered. The table below includes the list of regulations by other agencies which staff reviewed for applicable emissions limits. The specific emission limits and their impact on the BARCT assessment is included for each class and category discussed in the appendices for each of the equipment categories.

Table 2-4. Other Regulatory Requirements

Regulatory Entity	Regulation/Rule Title	Relevant Units/Equipment
Bay Area Air Quality Management District	Regulation 9-10-301 – Refinery-Wide NOx limit for boilers, steam generators and process heaters, excluding CO Boilers	Heater and Boiler
	Regulation 9-10-307 – Refinery NOx Emission Limit for CO Boilers	FCCU
	Regulation 9, Rule 9 - Limits Emissions of NOx from Stationary Gas Turbines	Gas Turbine
San Joaquin Valley Air Pollution Control District	Rule 4306 – Boiler, Steam Generators, and Process Heaters – Phase 3	Heater and Boiler
	Rule 4320 – Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr	Heater and Boiler
	Rule 4311 – Flares	Flare and Thermal Oxidizer
	Rule 4313 – Lime Kilns	Petroleum Coke Calciner
Texas Commission on Environmental Quality	Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	Petroleum Coke Calciner
		FCCU
		Gas Turbine
		SRU/TG Incinerator

Assess Pollution Control Technologies

Assessment of Pollution Control Technologies

The next step is to research the commercially available emission control technologies and seek information on any emerging emission control technologies. As part of this assessment, staff met with multiple air pollution control vendors who have experience working with petroleum refineries and related industries to discuss NOx emissions control technologies. Staff also invited several vendors to present at the Working Group Meetings to address the stakeholders' concerns regarding the available and applicable technologies for the purpose of NOx emissions reduction. Staff also relied on the third-party consultants who also reached out to the technology vendors and had discussions on the level of emission controls that can be achieved with the state-of-the-art technology. Appendix A has descriptions for the NOx control technologies, emission reduction performance, and the applicable units they can control; the following section contains an overview of the control technologies staff evaluated.

Table 2-5. Technology Vendors

Vendor	Control Equipment
CECO Peerless	SCR and AIG systems
Zeeco	LNBs and ULNBs
Cormetech	SCR catalyst options
Umicore	SCR catalyst options
John Zink Hamworthy	LNB, ULNB, SOLEX™ burners, and SCR Systems
ClearSign™	Duplex™ Technology

Table 2-6. Commercially Available NOx Controls per Equipment Category

Technology	Heater	Boiler	FCCU	Coke Calciner	Gas Turbine	SRU/TG Incinerator	Vapor Incinerator
Water/Steam Injection	X	X			X		
Flue Gas Recirculation	X	X			X		
NOx Combustion Additive			X				
Ultra-Low NOx Burners	X	X				X	X
Low NOx Burners	X	X				X	X
Selective Catalytic Reduction	X	X	X	X	X	X	X
LoTOx™ w/ Wet Gas Scrubber	X	X	X	X		X	X
UltraCat™	X		X	X			

The most utilized NOx controls are low- or ultra-low NOx burners and post-combustion controls such as low temperature oxidation process for NOx control (LoTOx™), UltraCat™ catalyst filter manufactured by Tri-Mer Corporation (UltraCat™), and SCR. The table below demonstrates the potential achievable NOx reductions and Appendix A contains detailed descriptions of the control technology.

Table 2-7. NOx Control Technologies, Application, and Performance

NOx Control Technologies	Application	Achievable Performance
LoTOx™ or UltraCat™ or SCR	Petroleum Coke Calciner, FCCUs	~95% Reduction
SCR or ULNB with SCR	Boilers/Process Heaters, Gas Turbines	Greater than 95% Reduction
ULNB	Boilers/Process Heaters fueled by Refinery Fuel Gas	20 – 30 ppmv[(1)] Optimal installation 40 – 50 ppmv[(1)] Sub-Optimal installation
ULNB	SRU/TG Incinerators, Sulfuric Acid Plants, Thermal Oxidizers (operating on refinery fuel, renewable fuel, or natural gas)	20 – 30 ppmv[(1)]
ULNB[(1)]	Boilers fueled by Natural Gas	5 ppmv[(1,2)]

(1) Based on a 3 percent O_2 correction
(2) Rapid Mix™ burner (RMB) from John Zink

In addition to the commercially available technologies, staff evaluated several emerging technologies that are currently not widely available but have demonstrated the potential for emission reductions in the future. The following table summarizes the emerging technologies, and their application and potential NOx reduction.

Table 2-8. Summary of Emerging Technology, Application, and Performance

NOx Control Technologies	Potential Applications	Potential Performance (ppmv at 3% O_2)
ClearSign™	Boilers/Process Heaters	<9
Great Southern Flameless	Process Heaters	<10
Solex™	Process Heaters	<5

The ClearSign™ emerging technology is already being implemented at local facility. The ClearSign Core™ technology operates like a traditional ULNB burner and is a direct burner replacement. There is currently a demonstration project that began March 2021 at World Oil, where ClearSign™ Core burner technology was installed in a heater with a rated heat input capacity of 39 MMBtu/hr equipped with five burners. The unit is currently achieving around 29.3 ppmv and is anticipated to achieve even lower NOx levels once the burners are further optimized. Further discussion on the ClearSign™ Core technology can be found in Appendix A.

PR 1109.1 includes a 9 ppmv NOx limit for process heaters less than 40 MMBtu/hour based on the potential of these emerging technologies. To allow time for the technology to develop, the

9 ppmv limits will not be required until ten years after rule adoption and once 50 percent or more of the burners are replaced or the replaced burners represent 50 percent or more of the heat input of the process heaters.

Initial BARCT Emission Limit and Other Considerations

After completing the technology assessment, staff recommends an initial BARCT NOx emission limit established using information gathered from the technology assessment. All provided emission concentration values (i.e., initial and final) in this report have the unit of part per million volume (ppmv) based on a dry basis. Additionally, staff evaluates other considerations that could affect the emission limits that represent BARCT, including ammonia limits if SCRs are likely to be installed, CO limits, averaging times, and conditional limits for those units operating close to the BARCT NOx limits. In addition, staff evaluates units that are considered outliers due to low-emissions, low-use, or high cost-effectiveness.

Ammonia Emissions

Currently, when post-combustion equipment such as SCR is being permitted, ammonia emissions from ammonia slip are evaluated. Under Regulation XIII – New Source Review (Regulation XIII), the BACT ammonia concentration limit for SCR systems is 5 ppmv. Staff did consider including an ammonia concentration limit in PR1109.1 but believes that this is a Regulation XIII issue and will be best addressed during permitting process. Evaluating the ammonia BACT limit during permitting provides the opportunity for an individual evaluation of the ammonia limit per equipment to ensure that the proposed NOx limit in PR 1109.1 is achieved. Any additional provisions for monitoring ammonia will also not be included in PR 1109.1 but may be required during permitting. When considering technical feasibility and costs of control equipment, staff assumed a 5 ppmv ammonia limit would be applied.

Carbon Monoxide Limits

In addition to NOx limits, PR 1109.1 establishes CO limits in order to maintain CO emissions. The South Coast AQMD region is in attainment for CO but is seeking to prevent any increase in CO emissions, which has the potential to rise when NOx emissions are controlled. The CO limits included in PR 1109.1 reflect limits in existing permits. PR 1109.1 allows operators to retain existing CO permit limit, if it is higher than the proposed CO limit in PR 1109.1; however, facilities with CO limits in their existing permits that are lower than the levels in the proposed rule will be required to maintain those lower CO permit limits.

Averaging Times

Averaging times are another key consideration when establishing the NOx limit. The need for appropriate averaging times was frequently discussed with Norton Engineering during staff's BARCT assessment. Norton Engineering stressed the need for longer averaging times for the facilities to comply with the low-NOx limits being proposed. A more detailed discussion of averaging times for each equipment category is available in Appendix B through Appendix G. Table 2-9 summarizes these averaging times.

Cost-Effectiveness and Incremental Cost-Effectiveness Analyses

Cost-Effectiveness and Incremental Cost-Effectiveness Analyses

Once the technical assessment is complete, staff evaluates the cost-effectiveness of initial BARCT NOx emission limit, or range of potential limits. If the NOx controls that achieved the maximum emission reduction is not cost-effective, the next level of control is evaluated.

Cost-effectiveness is measured in terms of cost of the control method to meet the proposed NOx limit per tons of NOx reduced over the lifetime of the control equipment. The data needed to conduct the cost-effectiveness analysis includes capital and installation costs, operating and maintenance costs, emission reductions, discount rate, and equipment life. If the cost per ton of emissions reduced is within a defined threshold, the control method is considered to be cost-effective.

The South Coast AQMD relies on the Discounted Cash Flow (DCF) method which converts all costs, including initial capital investments and costs expected in the present and future years of equipment life, to a present value. In the interest of transparency and comparability, staff is also providing cost-effectiveness values based on the Levelized Cash Flow (LCF) method in Chapter 4 and Appendix B through Appendix G. The main difference between the DCF and LCF methods lies in how the costs are expressed. DCF utilizes the present value, or a stream of all present and future costs discounted to and summed up in the same initial year. The LCF method annualizes the present value of total costs as if all costs, including the initial capital investments, would be paid off in the future with an equal annual installment over the equipment life. For this reason, a cost-effectiveness value as calculated using DCF is always lower than that calculated using LCF. The current DCF threshold for NOx and SOx was established in 2010 SOx RECLAIM BARCT assessment as $50,000 per ton reduced. The $50,000 per ton of emissions reduced threshold was also used in the 2016 AQMP. If the threshold is inflated to represent current dollars using the Marshall and Swift Index, the current value for DCF threshold would be about $60,000 per ton of emissions reduced.

Incremental Cost Effectiveness Analysis

Finally, California Health and Safety Code Section 40920.6(a)(3) states that an incremental cost-effectiveness assessment should be performed on identified potential control options that meet air quality objectives. To determine the incremental cost-effectiveness under this paragraph, South Coast AQMD calculates the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option. Once the BARCT assessment is complete and NOx limits are established, staff considers incrementally more stringent options to demonstrate that the NOx limit represents the “maximum degree of reduction achievable by each class or category”. The incremental cost-effectiveness assessment is presented in Chapter 4.

BARCT Emission Limit

According to California Health and Safety Code Section Sections 40920.6(a)(1) and 40920.6(a)(2), potential controls to meet an air quality objective, which is to assess the BARCT emission limits, must be identified and the cost-effectiveness assessment should be conducted thereafter. The final proposed BARCT emission limit for each class and category is the emission limit that achieves the maximum degree of emission reductions and is determined to be cost-effective. Staff evaluated the cost-effectiveness for the most stringent initial BARCT emission limit. If the most stringent initial BARCT limit is not cost-effective, the next less stringent limit was assessed. The following table summarizes the proposed NOx limits that represent BARCT, the applicable CO limits, and the proposed averaging times for each class and category.

Table 2-9. Proposed NOx and CO Emission Limits

Equipment Category		Emission Limits (ppmv)(1) NOx	Emission Limits (ppmv)(1) CO	Averaging Time (Rolling)(2)
Boilers	<20 MMBtu/hr	40/5(3)	400	24-hour
Boilers	≥20 – <40 MMBtu/hr	40/5(3)	400	24-hour
Boilers	≥40 – ≤110 MMBtu/hr	5	400	24-hour
Boilers	>110 MMBtu/hr	5	400	24-hour
Flares		20	400	2-hour
FCCU		2 5	500	365-day 7-day
Gas Turbines Fueled with Natural Gas		2	130	24-hour
Gas Turbines Fueled with Gaseous Fuel other than Natural Gas		3	130	24-hour
Petroleum Coke Calciners		5 10	2,000	365-day 7-day
Process Heaters	< 20 MMBtu/hr	40/9(4)	400	24-hour
Process Heaters	≥20 – <40 MMBtu/hr	40/9(4)	400	24-hour
Process Heaters	≥40 – ≤110 MMBtu/hr	5	400	24-hour
Process Heaters	>110 MMBtu/hr	5	400	24-hour
SRU/TG Incinerator		30	400	24-hour
SMR Heaters		5	400	24-hour
SMR Heaters with Gas Turbine		5	130	24-hour
Sulfuric Acid Furnaces		30	400	365-day
Vapor Incinerators		30	400	24-hour

(1) BARCT NOx limits for all equipment categories are specified at 3% oxygen correction, except for Gas Turbines and SMR Heaters with Gas Turbine which are specified at 15% oxygen correction.

(2) Averaging times apply to units operating a certified CEMS. Requirements, including averaging times, for units without CEMS are in the source test subdivision of the rule.

(3) The 40 ppmv limit is effective 6 months after rule adoption, the 5 ppmv limit is effective upon burner replacement.

(4) The 40 ppmv limit is effective 6 months after rule adoption, the 9 ppmv limit will be effective ten years after rule adoption burner replacement.

Boilers and Process Heaters Less than 40 MMBtu/hour

The BARCT assessment for boilers and process heaters less than 40 MMBtu/hour lists two NOx limits. As detailed in Appendix B, the technical assessments concluded 5 ppmv NOx is technically feasible based on burner technology for boilers less than 40 MMBtu/hour; however, the cost-effectiveness analysis concluded it was not cost-effective to require replacement of existing burners. The assessment of the existing units showed all boilers less than 40 MMBtu/hour are currently achieving less than 40 ppmv. PR 1109.1 requires boilers less than 40 MMBtu/hour to comply with the 5 ppmv limit when 50 percent or more of the burners are replaced or the replaced burners represent 50 percent or more of the heat input of the boiler.

Similarly, as detailed in Appendix B, the technical assessments concluded 9 ppmv NOx is technically feasible based on emerging burner technology for process heaters less than 40 MMBtu/hour; however, the cost-effectiveness analysis concluded it was not cost effective to require replacement of existing burners. The assessment of the existing units showed all but two process heaters less than 40 MMBtu/hour are currently achieving less than 40 ppmv. PR 1109.1 has a different timeframe for when a process heater must comply with the 9 ppmv limit because it is based on emerging technology. The 9 ppmv limit will not be required until ten years after rule adoption and only when 50 percent or more of the burners are replaced or the replaced burners represent 50 percent or more of the heat input of the process heaters.

Establishing Conditional NOx Limits

Once the NOx limits were established, staff evaluated the data to see if there are any cost outliers. Cost outliers tend to arise when units are used at low capacities, if the emission reductions are low, which typically occurs for units performing near the proposed BARCT NOx limits. Staff tries to provide relief for projects with very high costs that do not result in significant emission reductions. South Coast AQMD rules typically address these outliers by including low-use or low-emitting exemptions, or by allowing a higher conditional limit for units already achieving close to the proposed limit. Staff formerly referred to these as “near-limits” but will now refer to them as “conditional limits,” as conditional limits better describe these alternative emission limits as the rule will include conditions for when a unit can be subject to these limits.

Facilities cannot install a new NOx control technology and request the conditional limit for that unit. The intent of the conditional NOx limit is to recognize units with existing NOx control technology that are meeting the conditional limit at times, but possibly not continually, or can take action to lower the emissions to the conditional limit. For example, facilities may be able to reduce emissions on well-controlled units to below the conditional limits by performing maintenance, tuning the SCR, upgrading catalyst, or improving the ammonia injection grid. The conditional limit could address concerns with stranded assets for those facilities previously investing in expensive controls. The rule will require those units to have a conditional permit limit shortly after rule adoption. The short timeframe is because those units should already be achieving below, or close to, the proposed conditional limits with little to no modifications needed to meet conditional limits. Units performing below the NOx concentration limit in Table 1 of PR 1109.1 will not be eligible to use the conditional limit, regardless of whether the unit has a permit condition with a higher NOx limit. Conditional NOx and CO emission limits are listed for each class and category. PR 1109.1 includes separate provisions for units listed in Attachment D of PR 1109.1. These units are pre-qualified, and operators are not required to implement an early permit submittal, and the NOx level established for the unit may be higher than Table 2 NOx Conditional Limits. An operator that is making changes to their unit to meet a Table 1 or Table 2 NOx limit will need to be sure that all requirements are met, including requirements if Regulation XIII – New Source Review is triggered.

WSPA Comment on Conditional Limits

Staff has received a public comment requesting to clarify that the proposed conditional limits are in fact BARCT for the sources to which they apply. Staff agrees with this interpretation. In essence, the proposed conditional limits apply to specific categories of sources that meet the criteria of having both a high cost-effectiveness and minimal potential for emission reductions if they were held to the otherwise-applicable BARCT limit. In addition, these sources are expected to be able to meet the conditional limits without installing new control equipment. Finally, the sources subject to the conditional limits were selected so as to ensure that the sources remaining in the original class or category of sources analyzed for BARCT determination would have an overall cost-effectiveness not exceeding $50,000 per ton of NOx reduced. According to the California Supreme Court, the District's selection of a class or category of source for BARCT rules will not be disturbed unless it is "arbitrary, capricious, or irrational." *American Coatings Ass'n. v. South Coast Air Quality Management Dist.*, 54 Cal. 4th 446, 474 (2012). Review under the arbitrary and capricious standard is more deferential than the substantial evidence standard (*American Coatings*, 54 Cal. 4th 446, 475). There the court noted that the District carefully considered the comments of the affected industry and provided a reasoned explanation for its choices. Therefore, the court held "We will not disturb the District's judgment simply because there is evidence, even substantial evidence, supporting a different classification." (*American Coatings, supra,* 54 Cal. 4th 446, 475).

Establishing Interim NOx Limits

PR 1109.1 includes interim limits that will serve as a bridge after facilities transition out of RECLAIM before they are required to meet the proposed limits in PR 1109.1. U.S. EPA has commented that since facilities in RECLAIM are operating under an emissions cap, an enforceable mechanism, such as interim limits, are needed to ensure emissions from each source do not increase and adversely affect progress towards attainment and to ensure compliance with Section 110(l) of the federal Clean Air Act. Interim limits are set at levels to prevent backsliding, reflect current NOx emission levels, and are not intended to require the facilities to install additional emission controls. Staff evaluated existing NOx concentration levels that are currently being achieved based on existing permits, source tests, and CEMS data. Interim NOx and CO emission limits are listed in the individual sections for each class and category.

WSPA Interim Limit Comment

During the rulemaking process, the WSPA provided an alternative option to the interim limits. WSPA proposed facilities stay in the RECLAIM program until all units at the RECLAIM facilities meet the NOx emission limits in PR 1109.1. Due to the number and scope of emission control projects that will be required to comply with PR 1109.1, staff anticipates there could be some units that do not meet the PR 1109.1 NOx limits approximately until 2033. Under the WSPA proposal, facilities would remain in the RECLAIM program unit 2033 or beyond. Further, under this approach, facilities could use RTCs in lieu of installing emission control equipment until the last unit was required to meet the PR 1109.1 NOx emission limit. Staff consulted with the U.S. EPA and CARB, and both agencies agreed that use of RTCs cannot be used to meet BARCT limits established under Proposed Rule 1109.1 as this approach would be in direct conflict with the intent of AB 617. Staff had a detailed discussion of this approach in the July 2021 RECLAIM Working Group Meeting.

BARCT Compliance Timeline

Assembly Bill 617 requires BARCT implementation by December 31, 2023. By definition under the Health & Safety Section 40406, BARCT is an "emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source." As such, staff conducted an extensive BARCT analysis in accordance with the state law evaluating various emission control technologies and their emission reduction performance, as well as costs for each class and category of equipment. The lower the NOx concentration limit required during the operation of the refinery equipment; the more emission reductions are generated. Maximizing NOx emission reductions not only satisfies the goals of a BARCT assessment, but it is also critical in meeting the region's ambient air quality standards as NOx is a constituent of ozone pollution and precursor to PM. According to the 2016 AQMP, the region needs to reduce NOx emissions 45 percent by 2023 and 55 percent by 2031 in order to meet the 80 ppb and 75 ppb ozone standards, respectively. As noted earlier in this staff report, the 2016 AQMP directed the transition from RECLAIM into command-and-control approach, and in doing so, reduce NOx emissions by at least 5 tons per day. Not achieving these NOx emission reductions also puts the burden on other sources to reduce their emissions further to make up for what is not achieved by this rule.

In conducting the BARCT NOx limit, the analysis focused on technologies that can achieve the maximum degree of reduction. For most equipment categories such as large boilers and heaters greater than or equal to 40 MMBtu/hour, this technology is Selective Catalytic Reduction or "SCR." Large boilers and heaters are the largest emissions category under PR 1109.1, representing approximately 60 percent of the NOx emissions. Low NOx burners are another control technology that could more easily be replaced in existing units at a lower cost than SCR, but the emission reductions are also lower potentially achieving 40-50 ppm. On the contrary, more effective NOx controls, such as ultra-low NOx burners (ULNB) can reduce NOx to 25-30 ppm, and if installed in combination with a Selective Catalytic Reduction (SCR), which reduces NOx 90-95%, can achieve less than 2 ppm. Thus, in satisfying the BARCT goal of "maximum degree of reduction achievable," staff initially proposed a 2 ppm NOx limit for large heaters and boilers to maximize emission reductions but due to safety concerns with installing ULNB in older units and the high costs of control technology to achieve 2 ppm, such as multiple ammonia injection grids, it is determined to not be cost effective for large heaters and boilers to meet 2 ppm. However, it is cost effective to achieve 5 ppm with less costly and technically feasible control technology such as a single stage SCR.

The affected refineries were built 50 to over 100 years ago and while equipment has changed over the years, most of the equipment affected by the rule is old and the spacing configuration of the sites are dense. Thus, to install pollution control requires creative engineering and design to accommodate the space necessary and perform properly. Some projects currently taking place involve building vertically requiring deep earth pylons to support the structure housing the control technology or constructing complex ducting to house the SCR catalyst beds that stretch long distances horizontally away from the basic equipment. So, while technically these projects could feasibly be constructed, the costs are in the millions of dollars which have been provided by the refineries and used in the BARCT analysis. Needless to say, time will be needed to design and complete these complex engineering projects necessary to install the controls that will achieve the maximum emission reductions from a 5 ppm NOx limit for large heaters and boilers as opposed to more simple projects, such as low-NOx burners, that would take less time but result in much less emission reductions from a higher 40-50 ppm NOx limit.

The proposed rule provides various options, under the I-Plan, by which an affected facility is required to meet emission reduction targets by certain deadlines crafted to ensure implementation of BARCT including the necessary steps for a successful project. Such necessary steps include design and engineering, permit application submittal, permit evaluation and issuance, budgeting, logistics, purchasing equipment, installation, and testing. Again, the affected facilities are decades old so over time space to install new control equipment has become very limited. The staggered structure of the deadlines in the options reduce demand for certain resources since the refineries will be competing for same pool of skilled labor, equipment manufacturers, source testing companies, etc. In addition, integrating projects into the scheduled turnarounds at the refineries assist in minimizing downtime and fuel supply disruptions. Refineries turnarounds are typically every three to five years, but certain complex equipment, such as the FCCU and crude unit, could have longer turnaround times of eight to ten years. In those cases, if the project turnaround is scheduled before the first phase, then those projects will likely be slated for their next turnaround time in eight to ten years. The I-Plan options are designed for early and high emission reductions that allow for longer implementation time for the units that have longer implementation schedules.

Other implementation considerations include the number of highly complex projects that will result from the proposed rule. Staff estimates approximately 75 SCR projects and 25 SCR upgrades needed to meet the stringent NOx limits, which need time to be implemented, especially as noted earlier there are competitive demands for resources. SCR projects tend to be customized to the site and location and require complex engineering due to the challenges in integrating equipment within the existing facility structure. These projects are costly ranging from $10 million to $70 million to complete, with total facility cost ranging from $179 million to one billion dollars.

While AB617 requires implementing BARCT by December 31, 2023, it would be unreasonable and unfeasible to *fully* implement, such as achieving BARCT limits, for all BARCT projects subject to PR1109.1. However, it should be noted, some BARCT projects will be fully implemented, and emission reductions will be achieved before December 31, 2023. In addition, with a deadline of January 1, 2024 to demonstrate compliance with 50% emission reductions from the largest refinery in the region, Option 4 alone will achieve over one ton per day of NOx emission reductions or 16 percent of the total project emission reductions. If time is not provided for the implementation of the other projects, the proposed rule risks not achieving over six tons per day of emission reductions since it is just not feasible to implement these complex emission reduction projects in such a short period of time given all the elements in the process as discussed earlier. Again, due to the high number of affected units requiring control device installations, potentially limited trained labor pool, competition for equipment and material, high cost of the projects, compliance with permitting and CEQA, not all projects can feasibly be completed to meet the stringent NOx limits in the rule. Feasibility is a parameter in determining BARCT so if the implementation to install SCR to achieve the stringent limit of 5 ppm is not feasible, then the BARCT analysis would need to be modified to focus on low NOx burners and the NOx BARCT limit would be increased t to meet the December 31, 2023 deadline so likely fewer emission reductions would be obtained. This would affect the overall emission reduction benefit potential of the rule by not requiring the most stringent limit.

Finally, because technology evolves and improves over time, periodic checks as to what is current BARCT, an evaluation of any new pollution control technologies that are commercially available and cost-effective. If a shorter implementation schedule is a limiting factor in imposing stringent NOx limits, then higher NOx limits would be deemed BARCT for PR1109.1 resulting in less emission reductions, In addition, it is highly unlikely a revised BARCT analysis to lower, for example, a 40 ppm limit to 5 ppm in a future rulemaking would be cost effective as the incremental emission reductions would be smaller. Thus, foregone emission reduction potential as a result of not allowing longer feasible implementation time would have a permanent impact. PR 1109.1 is designed to achieve the greatest NOx emission reductions, with a strong emphasis on earlier reductions.

Clean Air Act Section 110(l) and Subdivision (o) Exemptions

State Implementation Plans (SIPs) are developed under Section 110 of the Federal Clean Air Act (CAA) for the purpose of protecting the National Ambient Air Quality Standards (NAAQS), which are health-based standards related to the six criteria pollutants: particulate matter (both $PM_{2.5}$ and PM_{10}), nitrogen dioxide, carbon monoxide, lead, sulfur dioxide, and ozone. Section 110(l) of the CAA prohibits the Environmental Protection Agency (EPA) from approving a revision to a SIP if the revision would interfere with any applicable requirement concerning attainment of the NAAQS or reasonable further progress toward attaining the NAAQS. Exemptions in subdivision (o) of Rule 1109.1 will comply with CAA Section 110(l) as the NOx emission limit requirements will not result in an emission increase that would interfere with the South Coast's ability to attain or maintain compliance with the NAAQS.

The exemptions provided in subdivision (o) are consistent with current operation and historical emissions data for the units. In addition, each unit must maintain or submit a complete permit application on or before July 1, 2022, pursuant to paragraph (f)(5) for an enforceable permit condition that will limit the usage. The following exemptions are provided in subdivision (o) of the rule:

Table 2-10. Exemptions and CAA Section 110(l)

Units	Rule Exemption	Requirement	Section 110(l) Demonstration
Process heaters and boilers less than 2 MMBtu/hour	Paragraph (o)(1)	Units used exclusively for space heating are exempt from Rule 1109.1	Units are subject to Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters
Low-use boilers less than 40 MMBtu/hour	Paragraph (o)(2)	Operated 200 hours or less per year and enforceable permit condition of 200 hours. Unit must also not be included in approved B-Plan or B-Cap	Impacts one boiler equipped with LNB and a permit limit of 9 ppm. Boiler is operated infrequently and only operated as a back-up when primary boiler is down for state inspections. No emissions increase or change in operation.
Low-use process heater rated greater than or equal to 40 MMBtu/hour	Paragraph (o)(3)	Units fired less than 15 percent of rated heat input capacity per calendar year and must have a permit condition that limits the firing rate.	Addresses limited number of process heaters that are infrequently used. Majority of all process heaters are utilized at 50 percent capacity or greater. No changes in operation or emissions increase.
FCCU bypassing post combustion control to conduct CO boiler inspection	Paragraph (o)(4)	Boiler inspections required under California Code of Regulations, Title 8, section 770(b)	CO boiler located downstream of FCC regenerator are subject to internal and external inspection pursuant to California Code of Regulations which require bypassing the CO boiler to conduct inspection
FCCU Startup Boilers and Process Heaters	Paragraph (o)(5)	Unit is operated 250 hours or less per calendar year and must have a permit condition that limits the operating hours to less than 250 hours per calendar year. Exempt	Heaters are only operated during FCC start-up which occurs once every several years. When operated, emissions are less than 0.002 tons

Units	Rule Exemption	Requirement	Section 110(l) Demonstration
		from subdivision (k), (l), (m) if unit is not included in approved B-Plan or B-Cap.	per day. No change from current operation or emissions increase.
Start-up and shutdown boilers and process heaters at sulfuric acid plants	Paragraph (o)(6)	Unit must have permit condition that limits the heat input to 90,000 MMBtu or lower per calendar year. Exempt from subdivision (k), (l), (m) if unit is not included in approved B-Plan or B-Cap.	Process heaters are only used to preheat the converter during startup of the processing unit and typically operated less than 10% of the annual limit specified in permit limit, based on annual fuel usage. Boiler located only at one facility and not operated when processing unit is operating. Only operated as much as needed. No change in current operation or emissions increase.
Boiler or process heater operating the pilot prior to start-up or shutdown	Paragraph (o)(7)	Startup/shutdown condition emissions not included in rolling average compliance demonstration	Applicable during startup /shutdown periods only. Startup duration limited pursuant to PR 429.1. Fuel usage is minimal when maintaining pilots, thus no emissions increase.
Flares (Ground)	Paragraph (o)(8)	Flare that emits less than or equal to 550 pounds of NOx per calendar year and must have an enforceable permit condition that limits emissions not to exceed 550 pounds per year	550-pound permit limit requirement is based on historical emissions data. No change in current operation or emissions increase.
Vapor Incinerators less than 2 MMBtu/hr per calendar year	Paragraph (o)(9)	Units emitting less than 100 pounds per calendar year and must have an enforceable permit condition Units emitting greater than 100 but less than 1,000 pounds per calendar year shall be exempt until unit replacement or ten years after rule adoption, whichever is sooner; must have enforceable permit condition that limits emissions to less than 1,000 pounds per calendar year	*No technical, feasible retrofit control option; Unit replacement only feasible option* Units emitting 100 pound or less per calendar year are infrequently used and only when needed. Permit limit based on historical emissions data, thus no emissions increase. Units emitting greater than 100 but less than 1,000 pounds per year permit limit is based on historical emissions data and will be required to replace with newer unit within 10 years. No change in operation or emissions increase from category.

To further ensure that the provided exemptions do not interfere with South Coast's ability to maintain or meet NAAQS, paragraph (f)(6) of the rule requires that any exemption exceedances pursuant to paragraphs (o)(2), (o)(3), (o)(5), (o)(6), (o)(7), (o)(8), and (o)(9) will require the owner or operator to submit a permit application for a permit condition based on Table 1 NOx Concentration Limit and corresponding CO concentration within six months of exceedance. Furthermore, subparagraph (f)(7)(B) addresses when an owner or operator fails to submit a permit application for an exempt unit and will be required to meet the applicable NOx and CO concentration limits in Table 1, 24 months after July 1, 2022. In addition, PR 1109.1 includes recordkeeping requirements for all units and includes provision to ensure applicable exemptions are being enforced such as meters to ensure that unit is below the applicable exemption. An owner or operator of Facility shall maintain the following daily records for each Unit, in a manner approved by the Executive Officer:

(A) Time and duration of startup and shutdown events;
(B) Total hours of operation;
(C) Quantity of fuel; and
(D) Cumulative hours of operation for the calendar year.

Staff believes that with the provision set forth in the rule has addressed the requirements of CAA Section 110(l) and is consistent with EPA requirements for adopting new rules into the SIP.

SUMMARY OF THE BOILER AND HEATER BARCT ASSESSMENT

Background

The largest equipment category under PR 1109.1 is the boilers and process heaters category, those units represent over 60 percent of the NOx emission sources at refineries and related industries. Process heaters are indirect-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. Process heaters are used extensively in various processing units throughout the refining industry with some having specialized applications, design arrangements, capacities, and combustion fuel sources. Staff evaluated several types of heaters as separate categories due to design differences. Specialized heaters are used for different purposes and may combust different fuel types, such as refinery gas, natural gas, pressure swing adsorption (PSA) off gas, sulfur, and hydrogen sulfide. Examples of specialized heaters include SMR heaters located in hydrogen plants which can have over 350 small burners and sulfuric acid furnaces which only have two large burners. Each burner type will have different design requirements for the intended application and have different associated costs.

Boilers are combustion sources used to generate the steam necessary for plant operations. Steam is primarily used for heating, separating hydrocarbon streams, hydrogen production, as a stripping medium, and to produce electricity by expansion through a turbine. There are also two specialized boiler applications that were considered separately: CO boilers and heat recovery boilers. The specialized boilers are typically associated with other units at the refinery. Although the term "boiler" typically describes a heater that generates steam, CO boilers in PR 1109.1 are heaters that process waste gas from the FCCU with an integral waste heat recovery system used to produce steam. There is one CO boiler that will be subject to PR 1109.1 and that unit will be subject to the NOx limits of the corresponding FCCU since the flue gases exit through a common stack. Similarly, a heat recovery boiler's main function is to recover excess waste heat to generate steam. However, unlike the CO boiler, heat recovery boilers are unfired units and are not a source of NOx; therefore, heat recovery boilers are not subject to PR 1109.1. An example of a heat recovery boiler is a boiler unit located downstream of a gas turbine referred to as a Heat Recovery Steam Generator (HRSG). Further discussion regarding the CO boiler can be found in Appendix B.

Due to the variety of boilers and process heaters that will be subject to PR 1109.1, staff segregated them into six major subcategories prior to conducting the BARCT assessment. Figure 2-3 shows the six subcategories.

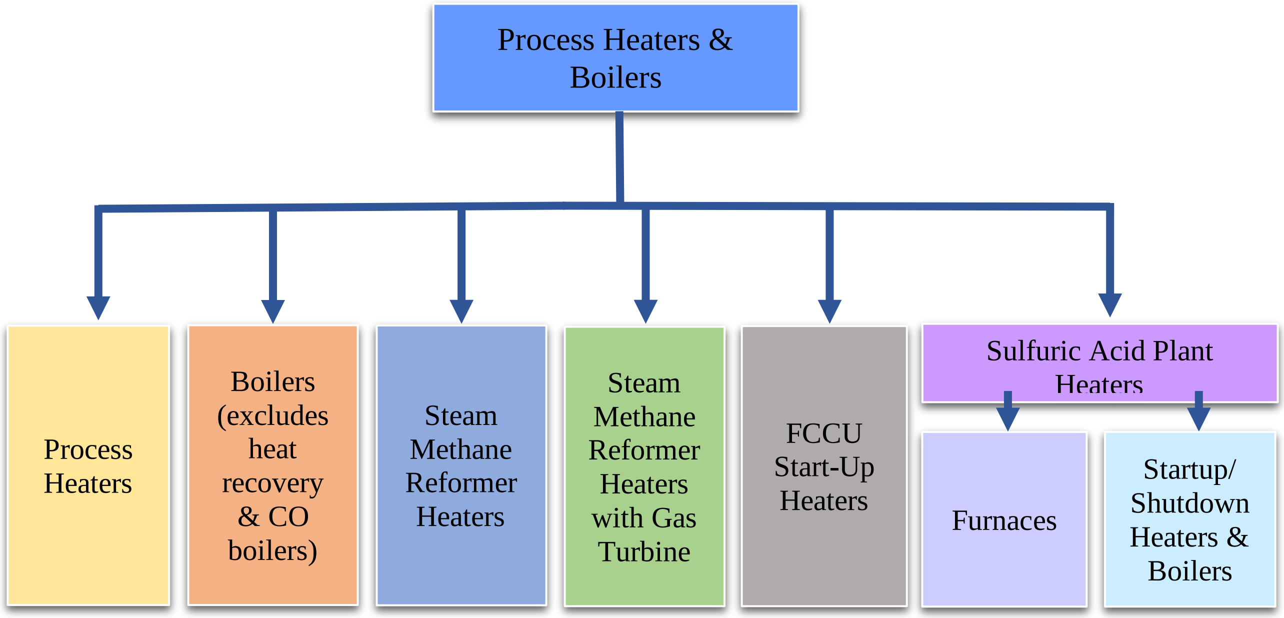


Figure 9. Six Major Sub-Categories of Boilers & Process Heaters Category

Each of the large boiler and process heater subcategories were divided into smaller categories based on size or maximum rated heat input in order to conduct a more granular BARCT assessment. Equipment was also grouped into subcategories to reflect the applicable technology control options. Staff divided the boilers and heaters into the four category sizes as described in the table below for the purpose of BARCT assessment.

Table 2-11. Boiler and Process Heater Size Categories

Heaters and Boilers Size Categories
<20 MMBtu/hr
≥20 to <40 MMBtu/hr
≥40 to ≤110 MMBtu/hr
>110 MMBtu/hr

The size categories were established based on the initial cost-effectiveness calculation that demonstrated it would not be cost effective to install SCRs on units less than 40 MMBtu/hour. Staff went one step further to separate categories into four size sub-categories to ensure the larger units with more emission reduction potential were not driving down the average cost-effectiveness of the class and category.

NOx Limits that Represent BARCT

The initial BARCT Assessment was presented in Working Group Meeting #9 on December 12, 2019 and updated in the following Working Group Meetings: #10 on February 18, 2020, #13 on August 12, 2020, #15 on November 4, 2020, #17 on February 4, 2021, #18 on February 11, 2021, and #19 on March 4, 2021. The large boiler and heater categories were reassessed using revised cost data to determine conditional limits at Working Group Meeting #22 on June 30, 2021. The table below summarizes the BARCT assessment for boilers and process heaters that were demonstrated to be technically feasible and cost-effective (see Appendix B for the detailed analysis).

Table 2-12. Summary of BARCT NOx Assessment for Boilers and Heaters

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Boiler (size MMBtu/hr)					
<20	12 ppmv	3 - 58 ppmv	9 - 30 ppmv	2 ppmv	40/5[3] ppmv
≥20 - <40	9 ppmv	3 - 81 ppmv	9 - 30 ppmv	2 ppmv	40/5[3] ppmv
≥40 - ≤110	25/2 ppmv	68 - 80 ppmv	5 - 9 ppmv	2 ppmv	5 ppmv
>110	5/2 ppmv	4.2 - 117 ppmv	5 - 9 ppmv	2 ppmv	5 ppmv
Process Heater (size MMBtu/hr)					
<20	12 ppmv	3 - 58 ppmv	9 - 30 ppmv	2 ppmv	40/9[4] ppmv
≥20 - <40	9 ppmv	3 - 81 ppmv	9 - 30 ppmv	2 ppmv	40/9[4] ppmv
≥40 - ≤110	25/2 ppmv	1.4 - 134 ppmv	9 - 30 ppmv	2 ppmv	5 ppmv
>110	5/2ppmv	1.5 - 70 ppmv	9 - 30 ppmv	2 ppmv	5 ppmv
SMR Heater					
All	2 ppmv	3.6 - 7.2 ppmv	5 ppmv	2 - 5 ppmv	5 ppmv
SMR Heater with Gas Turbine					
All	N/A	4.4 ppmv	N/A	3 - 5 ppmv	5 ppmv
Sulfuric Acid Furnace					
All	N/A	23 - 60 ppmv	N/A	2 and 20 ppmv	30 ppmv

(1) BARCT NOx limits for all equipment categories are corrected to 3% oxygen, except for SMR Heaters with Gas Turbine which are corrected to 15% oxygen.

(2) Concentration limits based on technology assessment represent the maximum NOx emission reductions for optimal installation without consideration for cost.

(3) The 40 ppmv limit is effective on January 1, 2023, the 5 ppmv limit is effective upon burner replacement.

(4) The 40 ppmv limit is effective on January 1, 2023, the 9 ppmv limit is effective 10 years after rule adoption upon burner replacement.

The BARCT assessment was conducted for each class and category listed in the table above. After conducting the BARCT assessment, some equipment size categories were combined for the same equipment type where the proposed NOx limit was the same. For example, where the BARCT assessment of related classes or categories of equipment concluded the same NOx limits were technically feasible and cost-effective, those categories were combined to streamline the rule requirements. For example, the boilers and process heater BARCT assessment evaluated four size categories (<20 MMBtu/hour, 20 to <40 MMBtu/hour, 40 to 110 MMBtu/hour, and >110 MMBtu/hour) but the PR 1109.1 Table 1 NOx limits are based on two size categories (<40 MMBtu/hour and ≥40 MMBtu/hour).

Conditional Emission Limits

Boilers and Process Heaters

Staff established conditional emission limits for boilers greater than 110 MMBtu/hour, process heaters between 40 to 110 MMBtu/hour, process heaters greater than 110 MMBtu/hour, and SMR heaters due to high cost-effectiveness for the class and category or high cost-effectiveness of some units.

For boilers greater than 110 MMBtu/hour, the class and category are cost effective for all units to meet the 5 ppmv NOx limit; however, there were a couple of units operating near the 5 ppmv limit with very high cost-effectiveness (more than $200,000 per ton reduced) that the rule will address. Staff identified five units operating at less than 7.5 ppmv as cost outliers and will include a conditional limit of 7.5 ppmv for boilers >110 MMBtu/hour. The potential emission reductions if those units were required to meet 5 ppmv is 0.02 tons per day with a cost of almost $20 million dollars.

Rule 1109.1 also establishes a second criteria that boilers greater than 110 MMBtu/hour with the potential emission reduction of more than 20 tons per year NOx emissions. The potential emission reductions are based on the difference of the baseline emissions and the PR 1109.1 Table 1 concentration limit, scaled to the baseline emissions. This second condition is to ensure those units with high emission potential will not be allowed to hold higher NOx limits. The conditional limits are intended for units that are already well controlled, including SCR controls.

For process heaters greater than or equal to 40 MMBtu/hour, the revised cost estimates that were provided by refineries to staff in March 2021 resulted in a cost-effectiveness greater than $50,000 per ton of NOx reduced. Staff used all of the revised refinery costs even though the facilities provided few details on the scope of the projects or justification for the significant cost increases received from some facilities. To reduce the average cost-effectiveness, staff identified units with high-cost effectiveness operating near the 5 ppmv limit in order to reduce the overall cost of the rule. An iterative process, summarized in the figure below, was used to identify the conditional NOx concentration level where the cost-effectiveness for units above the conditional emission limit would be less than $50,000 per ton of NOx reduced. The NOx reduction projects for units already achieving lower NOx emission typically represent cost outliers. Table below shows the Boilers and Heaters performing under conditional limits.

Table 2-13. Boilers and Heaters Performing under Conditional Limits

Facility ID	Category	Device ID	Size (MMBtu/hr)	Proposed BARCT limit (ppmv)
800436	Boiler	D1122	140	7.5
800026	Boiler	D1550	245	7.5
181667	Boiler	D1236	340	7.5
181667	Boiler	D1239	340	7.5
171109	Boiler	D429	352	7.5
800436	Heater	D384	48	18
800436	Heater	D385	24	18
174655	Heater	D419	52	18
181667	Heater	D231	60	18
181667	Heater	D232	60	18
181667	Heater	D234	60	18
181667	Heater	D235	60	18
800436	Heater	D770	63	18
181667	Heater	D950	64	18
800026	Heater	D768	110	18
800026	Heater	D6	136	22
800436	Heater	D388	147	22
171109	Heater	D78	154	22
800030	Heater	D643	220	22
174655	Heater	D532	255	22
174655	Heater	D63	300	22
800030	Heater	D82	315	22
800030	Heater	D83	315	22
800030	Heater	D84	219	22
800436	Heater	D388	147	22
800436	SMR Heater	D777	146	7.5
174655	SMR Heater	D1465	427	7.5

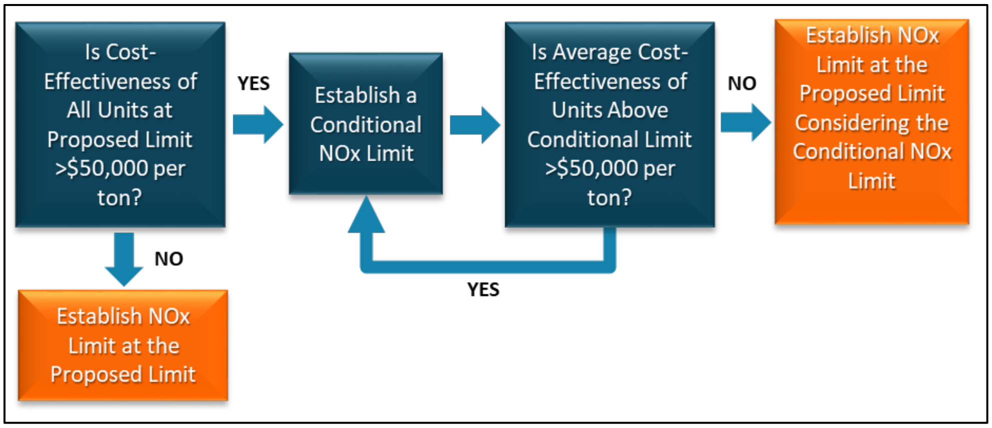
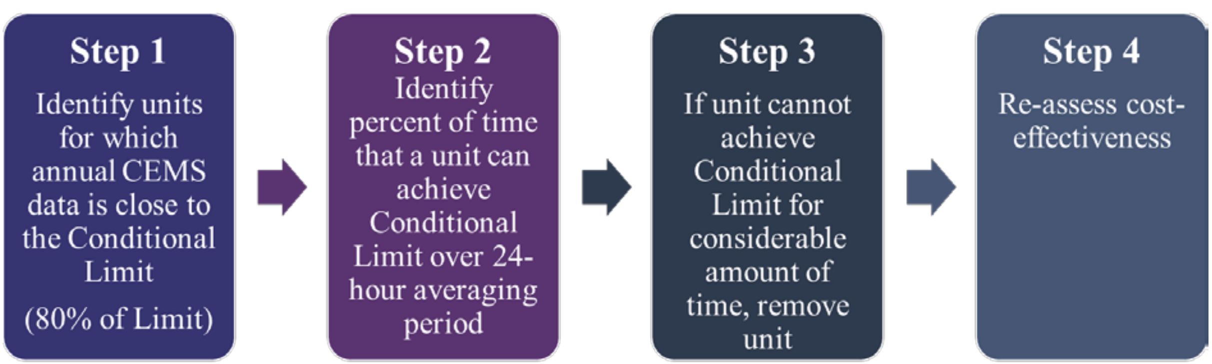


Figure 10. Process to Establish Conditional NOx Limits For Large Process Heaters

When staff presented the conditional NOx limit assessment, WSPA disagreed with the approach to remove cost outliers and commented that the process used to identify units that could potentially meet the conditional limits for boilers and process heaters greater than or equal to 40 MMBtu/hour was flawed. Staff relied on annual NOx CEMS data to identify the NOx levels that units could achieve. WSPA disagreed with this assessment as the units will be required to meet the Rule 1109.1 limits based on a 24-hour average. Staff presented the iterative process used for establishing the conditional limits, as shown in the above figure, by evaluating the overall cost effectiveness of the class and category and removing units from the average, starting with units performing near the proposed BARCT limit. The iterative process was repeated until the class and category cost effectiveness were less than $50,000 per ton of NOx reduced and the conditional limits was established based on that process. In addition, based on the WSPA comment on the averaging time used in the assessment, staff reviewed the CEMS data for the units performing near the established conditional limits to ensure the units could meet the conditional limits based on the proposed averaging time in the rule. While the RECLAIM program is based on annual compliance, command-and-control rules, such as PR 1109.1, require compliance to be demonstrated based on shorter averaging periods. Staff re-evaluated the CEMS data for the units performing below the conditional limits based on a 24-hour average to ensure those units met the conditional emission limit over a considerable amount of time (e.g., 80 percent). Refer to the appendices for more discussion and detailed analysis of conditional emission limit for each of the equipment classes.



In evaluating the process heaters between 40 and 110 MMBtu/hour and heaters greater than110 MMBtu/hour, several units with different sizes were identified with combined stacks. For the conditional limit assessment, staff considered units to fall into the larger category if even one of the combined units was less than110 MMBtu/hour.

Table 2-14. Applicable NOx Limit for Units with Combined Stacks

Unit Sizes for Combined Stacks			Unit Size for Determining NOx Limit Based
<40 MMBtu/hr	≥40 to ≤110 MMBtu/hr	> 110 MMBtu/hr	
Yes	Yes	No	≥40 to ≤110 MMBtu/hr
Yes	No	Yes	> 110 MMBtu/hr
Yes	Yes	Yes	> 110 MMBtu/hr
No	Yes	Yes	> 110 MMBtu/hr

For process heaters between 40 and 110MMBtu/hour, staff determined a conditional emission limit of 18 ppmv would reduce the cost-effectiveness to less than $50,000 per ton of NOx reduced. Rule 1109.1 also establishes a second criteria that facilities cannot apply for the conditional limit for process heaters between 40 and 110MMBtu/hour if the potential emission reduction project is more than 10 tons per year in NOx emissions. The potential emission reductions are based on the difference of the baseline emissions and the PR 1109.1 Table 1 concentration limit, scaled to the baseline emissions. This second condition is to ensure those units with high emission potential will not be allowed the higher NOx limits. The conditional limits are intended for units that are already well controlled, including SCR controls.

For process heaters greater than 110 MMBtu/hour, staff determined a conditional emission limit of 22 ppmv would reduce the cost-effectiveness to less than $50,000 with a second criteria for projects that had the potential to reduce emissions more than 20 tons per year; those projects have an average cost-effectiveness of $44,000 per ton of NOx reduced and represent 1.6 tons per day of NOx emission reductions from this class. Rule 1109.1 also establishes a second criteria that process heaters >110 that have a potential emission reduction of 20 tons per day of NOx are not eligible for the conditional 22 ppmv limit. The potential emission reductions are based on the difference of the baseline emissions and the PR 1109.1 Table 1 concentration limit, scaled to the baseline emissions. The specific units staff identified as meeting the conditional limits are listed in Appendix B.

SMR Heaters

For SMR heaters, three units were identified achieving greater than the proposed 5 ppmv BARCT NOx limit that had very high cost-effectiveness. The entire class and category is cost-effective, but these three units are cost outliers with an estimated Present Worth Value for SCR upgrade to meet 5 ppmv up to $10,000,000 with potential NOx emission reductions of 0.015 tons per day. For this category, the rule will include a conditional NOx limit of 7.5 ppmv. A more detailed discussion and analysis can be found in Appendix B.

Interim Limits

Boilers and Process Heaters

Staff established interim NOx and CO emission limits based on the current emission levels or existing permit limits for boilers and process heaters. The interim limit for boilers and process heaters less than 40 MMBtu/hour will be 40 ppmv as most units already have permit limits at 40 ppmv. However, there are two heaters in the less than 40 MMBtu/hour category that are currently performing above 40 ppmv – NOx concentrations are 58 and 96 ppmv. To address these two heaters, staff has included an interim limit of 60 ppmv for heaters with a rated heat input <6 MMBtu/hour and for any unit in the category that is operating an approved CEMS, will be able to incorporate the heater in a compliance plan which will be subjected to facility-wide interim emission rate of 0.03 lb/MMBtu for the process heater category. For the larger units, the NOx concentrations range from less than 2 ppmv to over 130 ppmv and most units do not have permit limits. Staff considered setting a high concentration limit that would accommodate all units, but if the interim limit was set too high, operators with controlled units with SCRs could stop running them as efficiently, which would result in backsliding. For boilers and process heaters greater than or equal to 40 MMBtu/hour, the rule will have a limit consistent with the original Rule 1109, which is a facility-wide boiler and heater limit of 0.03 pounds per MMBtu based on the maximum firing rate of the units. The averaging time will diverge from the Rule 1109 15-minute average and instead be consistent with the current annual regulatory construct of RECLAIM. All interim limits will allow a 365-day rolling average as the interim limits are intended to prevent backsliding and not place further regulatory requirements on the facilities. Most interim limits will apply until a unit is required to meet another PR 1109.1 emission limit; however, since the 0.03 pounds per MMBtu limit is based on all boilers and process heaters, that limit will apply until all the boilers and process heaters greater than or equal to 40 MMBtu/hour at that facility are required to meet another PR 1109.1 emission limit. This does not add an additional burden to the facility as the emission level of pound per MMBtu will decrease as controls are installed. Instead, this requirement it is to prevent the facility-wide level to increase as low-emitting units are removed from that total.

The rule also includes a third option of the I-Plan compliance schedule that allows a lower emission reduction target during the initial phase available only for those facilities with lower emissions from large boilers and process heaters either because they already implemented a considerable number of NOx control projects, or the facility has newer, lower-emitting units. Facilities that elect to comply with the third option under I-Plan compliance schedule will have to meet an interim limit of 0.02 pounds per MMBtu based on the maximum firing rate of the units. Staff anticipates two facilities (Chevron and Valero Refinery) are currently eligible for this compliance schedule option.

Facilities that elect to comply with a B-Cap will be held to an annual mass cap. Those facilities will be held to a mass cap based on the 2017 emissions.

SMR Heaters
The interim limit for SMR heaters will be set based on current emission levels. The emissions for SMR heaters vary considerably depending on if there are SCRs installed so there will be two interim limits: 20 ppmv for units with existing SCRs and 60 ppmv for units without existing SCRs.

Averaging Times
For the units greater than or equal to 40 MMBtu/hour, staff initially proposed an eight-hour averaging time. Staff’s third-party consultant Norton Engineering stressed the need for the longer averaging times to meet the low NOx levels being proposed. Due to the complexity and variability of the fuel composition in refinery fuel gas at facilities subject to PR 1109.1, Norton Engineering recommended a 24-hour averaging time to allow the facilities the time to achieve the proposed low-NOx levels. Demonstrating compliance of the concentration limit averaged over a period of time can be done when the emissions data is continuously monitored and collected. Units such as boilers and process heaters less than 40 MMBtu/hr that do not have CEMS will be dependent on periodic source tests to demonstrate compliance. Data collected during that source test will be based on approved source test protocols and are typically shorter periods of time such as 15-min or 2-hour averaging.

Carbon Monoxide Limits

PR 1109.1 establishes a 400 ppmv CO limit for boilers and process heaters, except for the SMR heater with a gas turbine where the CO limit is 130 ppmv, since these unit achieve lower CO levels. Any units with lower CO limits in existing permits will have to maintain the permitted limits.

Startup and Shutdown Boilers and Process Heaters

There are seven startup process heaters and one startup boiler that will be subject to PR 1109.1. Five of the heaters are used only during FCCU startup which can be once every 5 years. Two heaters and a boiler are used for sulfuric acid production units and are also used during unit startup. Based on the BARCT assessment, it is not cost-effective to retrofit these units due to the low emissions. FCCU startup heaters annual emissions are 0.002 tons per day, sulfuric acid start-up heaters are 0.00008 tons per day, and sulfuric acid start-up boiler is 0.0003 tons per day. These units will fall under a low-emissions exemption but will have to meet the applicable rule limits based on their size if the use exceeds the exemption threshold. The FCCU startup heaters will have a low-use exemption of 250 hours.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for boilers and heaters. All averaging times in the tables below apply to units operating a certified CEMS. Units not required to operate CEMS will be required to demonstrate compliance based on a source test performed over no longer than 2 hours.

Table 2-15. PR 1109.1 Emission Limits for Boilers and Process Heaters

BOILERS			
Rated Heat Input Capacity (MMBtu/hour)	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
<40	40/5[2]	400	24-hour
≥40	5	400	24-hour
PROCESS HEATERS			
Rated Heat Input Capacity (MMBtu/hour)	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
<40	40/9[3]	400	24-hour
≥40	5	400	24-hour
STEAM METHANE REFORMER HEATERS			
Equipment Category	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
SMR Heater	5	400	24-hour
STEAM METHANE REFORMER HEATERS WITH GAS TURBINE			
Equipment Category	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	15% O_2 Correction		
SMR Heater with Gas Turbine	5	130	24-hour
SULFURIC ACID FURNACES			
	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
Furnace	30	400	365-day

(1) Averaging times apply to units operating a certified CEMS, units not required to operate CEMS will be required to demonstrate compliance based on a source test performed no longer than 2 hours.

(2) The 40 ppmv limit is effective on January 1, 2023, the 5 ppmv limit is effective upon burner replacement.

(3) The 40 ppmv limit is effective 6 on January 1, 2023, the 9 ppmv limit is effective 10 years after rule adoption upon burner replacement.

Table 2-16. Conditional NOx Emission Limits for Boilers and Process Heaters

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
Process Heaters ≥40 – ≤110 MMBtu/hr	18	400	3	24-hour
Process Heaters >110 MMBtu/hr	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour

(1) Averaging times apply to units operating a certified CEMS, units not required to operate CEMS will be required to demonstrate compliance based on a source test performed no longer than 2 hours.

Table 2-17. Interim NOx Emission Limits for Boilers and Process Heaters

Unit	NOx	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time(1)
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraphs (f)(2) (*see following Table*)	400	3	365-day
SMR Heaters	20 ppmv[2]	400	3	365-day
	60 ppmv[3]			365-day
SMR Heaters with Gas Turbine	5 ppmv	130	15	365-day

(1) Averaging times apply to units operating a certified CEMS, units not required to operate CEMS will be required to demonstrate compliance based on a source test performed no longer than 2 hours.

(2) SMR Heaters with post-combustion air pollution control equipment installed before date of rule adoption.

(3) SMR Heaters without post-combustion air pollution control equipment installed before date of rule adoption.

Table 2-18. Interim NOx Emission Limits for Boilers and Process Heaters ≥40 MMBtu/hour

Units	An Owner or Operator that Elects to Comply with an Approved:	Facility NOx Emission Rate (pounds/million Btu)	Rolling Averaging Time
Boiler and Process Heaters ≥40 MMBtu/hour	B-Plan or B-Cap using I-Plan Option 3	0.02	365-day
	B-Plan	0.03	365-day

Facilities that elect to comply with a B-Cap will be held to an annual mass cap. Those facilities will be held to a mass cap based on the 2017 emissions.

SUMMARY OF PETROLEUM COKE CALCINER BARCT ASSESSMENT

Background

The Marathon (Tesoro Refinery) petroleum coke calciner is the only equipment of its kind in the South Coast Air District and is operating under the NOx RECLAIM program. Based on the 2018 NOx survey questionnaire, this petroleum coke calciner has two connected combustion devices, a rotary kiln and pyroscrubber, that share a common stack equipped with a single CEMS. There are no existing NOx controls, but the equipment has controls for SOx and particulate matter (PM). The preliminary BARCT assessment for this category was presented in Working Group Meeting #2 on June 14, 2018 and the final assessment was presented during Working Group Meeting #12 held on July 17, 2020. There are no specific South Coast AQMD regulatory requirements for the petroleum coke calciner beyond the requirements in RECLAIM. BARCT assessments were conducted for the petroleum coke calciner in 2005 and 2015 as part of the RECLAIM program which established NOx emissions limits of 30 ppmv and 10 ppmv, respectively. The next section will summarize the BARCT assessment for petroleum coke calciner. The complete BARCT assessment is included in Appendix C.

NOx Limits that Represent BARCT

Table below summarizes the petroleum coke calciner NOx concentration limits demonstrated to be technically feasible and cost-effective (see Appendix C for the detailed analysis).

Table 2-19. Summary of BARCT Assessment for Petroleum Coke Calciner

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Petroleum Coke Calciner	10 ppmv	65 –85 ppmv	N/A	5 ppmv	5 ppmv

(1) NOx limits are corrected to 3% oxygen

Interim Limits

Interim limit for the petroleum coke calciner is based on current operating conditions. PR 1109.1 will include a NOx interim limit of 85 ppmv and a CO interim limit of 2,000 ppmv at three percent oxygen, with a 365-day averaging period.

Averaging Times

PR 1109.1 establishes a 365-day rolling averaging time due to specific challenges of the petroleum coke calciner, such as: variability with the feed which affect NOx emissions; the petroleum coke calciner is a process unit and not an individual piece of combustion equipment; response times may be lower; and multiple pollutants need to be addressed. To ensure short-term NOx limits remain low, staff is also proposing a short-term NOx limit of 10 ppmv at three percent oxygen with a 7-day rolling average. This short-term limit will account for process variations in day-to-day operation of the petroleum coke calciner.

Carbon Monoxide Limits

PR 1109.1 establishes a 2,000 ppmv CO limit for the petroleum coke calciner. This limit is consistent with the existing permit limit for this unit.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for petroleum coke calciner. There are no conditional limits for the petroleum coke calciner because achieving BARCT of 5ppmv has been determined to be cost-effective.

Table 2-20. PR 1109.1 Emission Limits for Petroleum Coke Calciner

PETROLEUM COKE CALCINERS		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
5	2,000	365-day
10		7-day

Table 2-21. Interim NOx Emission Limits for Petroleum Coke Calciner

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Petroleum Coke Calciner	85	2,000	3	365-day

FLUID CATALYTIC CRACKING UNITS (FCCUs) BARCT ASSESSMENT

Background

There are five refineries that operate five FCCUs in the South Coast AQMD: Torrance, Chevron, Tesoro Refinery, Phillips 66, and Ultramar (Valero Refinery). The initial BARCT assessment for this category was presented in Working Group Meeting #2 on June 14, 2018. Initial BARCT assessment was completed and presented during Working Group Meeting #11 held on May 21, 2020. A follow up BARCT reassessment was presented in Working Group Meeting #22 on June 30, 2021. The BARCT reassessment for this category was conducted to address units performing near the proposed BARCT limit. Three of the FCCUs currently have SCRs in operation for which the outlet NOx concentrations range from 1.2 to 10 ppmv; one of the three currently operates at a level under 2 ppmv NOx on an annual basis. The other two FCCUs currently operate with no NOx controls and permit limits vary from 20 to 40 ppmv NOx; the outlet NOx concentrations range from 14 to 32 ppmv. The next section will summarize the BARCT assessment for FCCUs. The complete BARCT assessment is included in Appendix D.

NOx Limits that Represent BARCT

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the FCCU category (see Appendix D for the detailed analysis).

Table 2-22. Summary of BARCT Assessment for FCCU

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
FCCU(1)	2 ppmv	1.2 – 32 ppmv	40 – 125 ppmv	2 ppmv	2/5 ppmv

(1) NOx limits are corrected to 3% oxygen.

Conditional Limit

PR 1109.1 will include a conditional limit for the FCCU category due to the high cost-effectiveness of some units. Of the five FCCUs, four currently have SCR NOx control or are in the permitting stage to install SCR. One unit is operating below the proposed BARCT NOx limit of 2 ppmv, one unit has been designed to meet 2 ppmv NOx, two are operating around 8 ppmv NOx and determined to not be cost effective to add further control to reduce to 2 ppmv, and one unit has no SCR NOx control but determined to be cost effective to install an SCR to achieve the proposed BARCT NOx limit of 2 ppmv. Cost for those two facilities operating around 8 ppmv NOx to upgrade and meet 8 ppmv NOx was approximately $1 million to $3 million, but to completely replace the SCR or add new technology to meet 2 ppmv ranged from $75 million to $220 million due to the advanced technology and engineering and design in addressing space constraints. While it would be cost effective for those facilities to meet 8 ppmv NOx at $12,000 per ton NOx reduced, it would not be cost effective, at $108,000 per ton NOx reduced, to achieve 2 ppmv NOx.

Depending on the technology selected it would be cost effective for the FCCU without an SCR to either install an SCR at $24,000 per ton of NOx reduced or alternative technology that could achieve multi-pollutant control at $46,000 per ton NOx reduced.

Interim Limit

Similar to the other equipment categories, staff established interim NOx limits based on the current emission levels or existing permit limits for FCCUs at 40 ppmv based on a 365-day average at three percent oxygen correction. As no facility currently operates above 40 ppmv, this interim limit will ensure no action (e.g., installation of control) would need to take place before the BARCT or conditional limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT or conditional limit is met.

Averaging Times

PR 1109.1 establishes a 365-day averaging time due to specific challenges of the FCCUs. FCCUs are very large complex units and generate NOx by coke burn off within the regenerator, not through the combustion of fuels. When an operator makes corrective actions in response to a NOx exceedance, the response time to the operational changes will not be seen for several hours. Staff is also proposing a short-term NOx limit of 5 ppmv at three percent oxygen with a 7-day rolling average to ensure that short-term NOx limits also remain low. This short-term limit will account for process variations in day-to-day operation of the FCCU.

Carbon Monoxide Limits

PR 1109.1 establishes a 500 ppmv CO at three percent oxygen correction limit for all FCCUs. Units with lower CO limits in existing permits will have to maintain the permitted limits.

Emission Limit Summary

NOx control technologies such as SCR and LoTOx™ are commercially available and it is technically feasible and cost-effective to achieve the proposed levels. The table below summarizes the emission limits in PR 1109.1 for an FCCU.

Table 2-23. PR 1109.1 Emission Limits for FCCU

FLUID CATALYTIC CRACKING UNITS (FCCUs)		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
2	500	365-day
5		7-day

Table 2-24. Conditional NOx and CO Emission Limits for FCCU

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
FCCU	8	500	3	365-day
	16			7-day

Table 2-25. Interim NOx Emission Limits for FCCU

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
FCCU	40	500	3	365-day

SUMMARY OF THE GAS TURBINE BARCT ASSESSMENT

Background

There is a total of 12 gas turbines operating at refineries in the South Coast AQMD. All gas turbines are in the combined-cycle mode, nine of which have duct burners and three have no duct burners. Gas turbines and duct burners emissions are controlled by a post-combustion control system such as SCR. Out of 12 gas turbine units, two units are entirely fired with natural gas and ten units are fired with other fuels (e.g., refinery fuel gas or refinery mixed gas). In the mixed fuel turbines, natural gas is used as primary fuel and refinery fuel gas is used as secondary fuel. Some refineries use a tertiary gas (e.g., butane) in the natural gas/refinery gas mix feed to power the gas turbines on an as-needed basis to ensure more reliable power production. The next section will summarize the BARCT assessment for gas turbines. The complete BARCT assessment is included in Appendix E.

NOx Limits that Represent BARCT

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the gas turbine category (see Appendix E for the detailed analysis).

Table 2-26. Summary of BARCT Assessment for Gas Turbine

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Natural Gas	2 ppmv	1.1 – 1.8 ppmv	2 – 42 ppmv	2 ppmv	2 ppmv
Refinery Gas or Refinery Mixed Gas	2 ppmv	2.8 - 10 ppmv	9 - 50 ppmv	2 ppmv	2 ppmv

(1) Emission limits based on 15 percent oxygen correction.

Conditional Limit

Staff reviewed the BARCT assessment for the gas turbines fueled by natural gas which are operating close to the proposed BARCT limit and determined it would not be cost effective ($570,000 per ton of NOx reduced) for one unit with a NOx permit limit of 2.5 ppmv to take action and reduce down to 2 ppmv NOx. As such staff is proposing a conditional limit of 2.5 ppmv NOx and maintaining a BARCT NOx limit of 2 ppmv since it is cost effective ($15,400 per ton of NOx reduced) for the remaining units to install control and meet the 2 ppmv NOx.

Interim Limit

Similar to the other equipment categories, staff established interim NOx limits based on the current emission levels or existing permit limits for gas turbines at 20 ppmv based on a 365-day rolling average at 15 percent oxygen correction. As no facility currently operates above 20 ppmv NOx, this interim limit will ensure no action (e.g., installation of control) would need to take place before the BARCT or conditional limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT or conditional limit is met.

Averaging Times

Gas turbines will have a 24-hour rolling averaging time. For these units, staff initially proposed an 8-hour averaging time with respect to Norton Engineering's feedback that longer averaging times were necessary to achieve a 2 ppmv NOx limit. Due to the complexity and variability at facilities subject to PR 1109.1, longer averaging times were determined to be more appropriate. Norton Engineering's final report concluded the 8-hour average was too short to meet the 2 ppmv NOx limit and recommended a 24-hour averaging period. In order to retain the proposed 2 ppmv NOx limit, PR 1109.1 will include the 24-hour averaging time for gas turbines.

Carbon Monoxide Limits

PR 1109.1 establishes a 130 ppmv CO limit for all gas turbines, which is a typical limit found in current gas turbine permits. Any units with lower CO limits in existing permits will have to maintain the lower permitted limits, and units with higher limits may maintain the higher limit.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for gas turbines.

Table 2-27. PR 1109.1 Emission Limits for Gas Turbines

GAS TURBINES			
Fuel Type	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
	15% O_2		
Natural Gas	2	130	24-hour
Gaseous Fuel other than Natural Gas	3		

Table 2-28. Conditional NOx and CO Emission Limits for Gas Turbines

Fuel Type	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Natural Gas	2.5	130	15	24-hour

Table 2-29. Interim NOx and CO Emission Limits for Gas Turbines

Fuel Type	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Natural Gas or Gaseous Fuel other than Natural Gas	20	130	15	365-day

SULFUR RECOVERY UNITS/TAIL GAS INCINERATORS BARCT ASSESSMENT

Background

There is a total of 16 SRU/TG incinerators operating in the South Coast AQMD, 13 without stack heaters and 3 with stack heaters. The initial BARCT assessment was presented in Working Group Meeting #2 on June 14, 2018 and a follow up BARCT reassessment was presented during Working Group Meeting #10 held on February 18, 2020. The next section will summarize the BARCT assessment for SRU/TG incinerators. The complete BARCT assessment for this category is included in Appendix F.

Since the inception of RECLAIM in 1993 until 2010, the South Coast AQMD did not set any BARCT standards for the SRU/TG incinerators. However, as part of the BARCT assessment, the 2015 RECLAIM BARCT NOx limit was determined as 2 ppmv at three percent oxygen . Currently no units have been retrofitted with post-combustion control and their annual average outlet NOx concentrations are ranging from 4 to 98 ppmv at three percent oxygen correction, depending on the type of fuel fired and operating conditions.

NOx Limits that Represent BARCT

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the SRU/TG incinerator category (see Appendix F for the detailed analysis). The 2 ppmv NOx limits in the table below under the Assessment of South Coast AQMD Regulatory Requirements reflects the RECLAM 2015 NOx BARCT Assessment. The RECLAIM BARCT assessment differs from the assessment conducted for PR 1109.1. The RECLAIM assessment concluded that certain high emitting units were cost effective to retrofit to 2 ppmv; however, the PR 1109.1 assessment included all of the SRU/TG Incinerators and it is not cost-effective to achieve 2 ppmv.

Table 2-30. Summary of BARCT Assessment for SRU/TG Incinerator

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
All Units	2 ppmv	4 – 74 ppmv	27 ppmv	2 ppmv	30 ppmv

(1) Emission limits based on 3 percent oxygen correction.

Conditional Limit

Staff is not proposing a conditional limit for SRU/TG incinerators because there are no high-cost outliers in the Class and Category.

Interim Limit

Similar to the other equipment categories, staff established an interim NOx limit based on the current emission levels or existing permit limits for SRU/TG Incinerators at 100 ppmv based on a 365-day rolling average at 3percent oxygen. As no facility operates this unit above 100 ppmv NOx, this interim limit will ensure no action (e.g., installation of control) would need to take place before the BARCT limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT limit is met.

Averaging Times

For SRU/TG incinerators, the proposed rolling averaging time in PR 1109.1 is 24 hours based on Norton Engineering's recommendation. Staff initially proposed an 8-hour averaging time but later decided to extend the averaging time to 24 hours per Norton Engineering's recommendation for a longer averaging time in order to give the refineries the ability to diagnose an abnormal operational problem and take the necessary corrective action(s) before an exceedance occurs. Units that do not operate with a CEMS will have to demonstrate compliance based on a source test that cannot exceed 2 hours.

Carbon Monoxide Limits

PR 1109.1 establishes a 400 ppmv CO at 3 percent oxygen limit for SRU/TG incinerators. Units with lower CO limits in existing permits will have to maintain the permitted limits, and units with higher limits can maintain their permit limits.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for SRU/TG incinerators. Nine units out of 16 need to retrofit based on the proposed BARCT NOx limit. Achieving 2 or 5 ppmv with

SCR and LoTOx™ technologies were demonstrated to be technically feasible but not cost-effective.

Table 2-31. PR 1109.1 Emission Limits

SULFUR RECOVERY UNITS/TAIL GAS INCINERATORS		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2		
30	400	24-hour

Table 2-32. Interim NOx Emission Limits for SRU/TG Incinerator

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
SRU/TG Incinerators	100	400	3	365-day

SUMMARY OF THE FLARE AND VAPOR INCINERATOR BARCT ASSESSMENT

Background

There is a total of 14 flares and vapor incinerators operating in the South Coast AQMD, including one small open flare and 13 vapor incinerators, which include afterburners, incinerators, and thermal oxidizers. Since the units in this category are very small (1-30 MMBtu/hr), installing a SCR control technology is not cost-effective. The best NOx control option is burner control. Staff evaluated similar-sized units from the Rule 1147 universe to assess technical feasibility of 20 ppmv NOx level. Thermal oxidizers at refineries operate similarly to units at other facilities that are primarily used for VOC control. Source test results demonstrate that ULNB for thermal oxidizers can achieve 20 ppmv NOx level. Also, there is only one open flare in the PR1109.1 universe. Open flares cannot be retrofitted with LNB or ULNB; therefore, staff considers replacement with a low-NOx flare (20 ppmv or 0.025 pounds/MMBtu) to be the best option for these flares. The next section will summarize the BARCT assessment for flares and vapor incinerators. The complete BARCT assessment is included in Appendix G.

Proposed BARCT NOx Emission Limit for Flare and Vapor Incinerator

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the flare and vapor incinerator category (see Appendix G for the detailed analysis).

Table 2-33. Summary of NOx BARCT Assessment for Flare and Vapor Incinerator

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Afterburners, Vapor Incinerators, and Thermal Oxidizers	N/A	8 - 90 ppmv	20 ppmv	20 ppmv	20 ppmv
Flares	N/A	130 lbs/MMscf	Replacement with 20 ppmv flare (0.025 lbs/MMBtu) if throughput capacity >5%	20 ppmv	20 ppmv

(1) Emission limits based on 3 percent oxygen correction.

Conditional Limit

Staff is not proposing a conditional limit for flares; however, based on staff's review of the BARCT assessment for the vapor incinerators which are operating close to the proposed BARCT limit and determined it would not be cost-effective ($100,000 – $500,000 per ton of NOx reduced) for four units to take action and reduce down to 30 ppmv NOx. As such staff is proposing a conditional limit of 40 ppmv NOx and maintain a BARCT NOx limit of 30 ppmv since it is cost effective for the remaining units to replace burners and meet the 30 ppmv.

Interim Limit

Similar to the other equipment categories, staff established interim NOx limits based on the current emission levels or existing permit limits for vapor incinerators at 110 ppmv and flares at 105 ppmv based on a 365-day average at 3 percent oxygen. No facility currently operates above the respective interim NOx limits, ensuring no action (e.g., installation of control) would need to take place before the BARCT or conditional limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT or conditional limit is met.

Averaging Times

PR 1109.1 includes a 24-hour rolling average for vapor incinerators which will only apply to a few larger units with a CEMS. All other units will have to demonstrate compliance based on a source test that cannot exceed 2 hours.

Carbon Monoxide Limits

PR 1109.1 establishes a 400ppmv CO limits for all flares and incinerators. Any units with lower CO limits in existing permits will have to maintain the permitted limits, and units with higher limits may maintain the higher limit.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for flares and incinerators.

Table 2-34. PR 1109.1 Emission Limits

FLARES		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
20	400	2-hour
VAPOR INCINERATORS		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
30	400	24-hour

Table 2-35. Conditional NOx Emission Limits for Vapor Incinerator

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Vapor Incinerators	40	400	3	2-hour

Table 2-36. Interim NOx Emission Limits for Vapor Incinerator

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Flares	105	400	3	365-day
Vapor Incinerators	110	400	3	365-day

AVERAGING TIME DISCUSSION

Averaging time could have a direct impact on the level of complexity and the cost of an emission control unit. Lower averaging times will increase the complexity and cost of an emission control system (e.g., SCR) by limiting the fluctuations in controlled NOx emissions; therefore, requiring more consistent NOx emissions. To propose an averaging time that meets the technical feasibility and cost-effectiveness requirements in the BARCT assessment, short term NOx emission fluctuations have been evaluated for each class and category in PR 1109.1. These short-term emission fluctuations occur during the unit's normal operation and should be separated from startup, shutdown, and malfunction events.

To examine the impact of averaging time in more detail, the following simplified equation can be derived:

$$T_{fluct} = (E_{BARCT} \times T_{avg} \times DM) / \, [E_{fluct} \; - \; E_{BARCT}(1 - DM)]$$

Where T_{fluct} (hours) represents the allowable period that NOx emission fluctuation can occur before exceeding the BARCT NOx limit, E_{BARCT} (ppmv) represents the BARCT NOx limit assigned for the class or category, T_{avg} (hours) represents the assigned averaging time, and E_{fluct}

(ppmv) represents the current NOx emission fluctuation. The design margin, DM (fractional value), represents a "margin" that is generally applied to the design of equipment to ensure it can meet the guaranteed value (i.e., a factor of safety applied to the design). A typical design margin for refinery equipment is 10% (DM = 0.1), this means that for an SCR with a 2 ppmv guaranteed NOx emission limit, the equipment has the capability to run at NOx emission levels in the 1.8 ppmv range. If a fluctuation occurs and the NOx emission level increases to E_{fluct}, there is a finite period the refinery can take action in order to correct operation and get the equipment back to the 1.8 ppmv range before the BARCT NOx limit is exceeded.

Based on Norton Engineering's recommendation, two averaging times for 2 ppmv BARCT NOx limit with a 10 percent design margin have been compared:

Table 2-37. Demonstration of the Impact of Different Averaging Times on Emission Limits

Averaging Time (hour)	Time to make corrective action (min)	Fluctuation limit (E_{fluct}, ppmv)	Conclusion
2	15	3.4	Does not provide a suitable time period to diagnose an equipment malfunction
	60	2.2	
24	15	21	Reasonable time period to take action or diagnose an equipment failure before the fluctuation time is exceeded
	60	6.6	

Therefore, based on Norton Engineering's recommendation, staff proposed a 24-hour averaging time for units greater than or equal to 40 MMBtu/hour.

THIRD PARTY CONSULTANT ASSESSMENTS

Fossil Energy Research Corporation (FERCo) and Norton Engineering Consultants (NEC) presented the summary of their technical review and recommendations at Working Group Meeting #16 on December 10, 2020. The written reports of their findings and recommendations are included in the Appendices of the staff report. Staff's BARCT assessment was adjusted in accordance with the recommendations from each consultant.

Norton Engineering Consultants Assessment

Norton Engineering conducted an independent review of current BARCT for stationary source categories identified by staff. Norton Engineering also assisted staff with several technical recommendations for difficult or specialized units with unique arrangements such as the SMR heater with integrated gas turbine and petroleum coke calciner. These were provided to staff in separate smaller individual reports or write-ups. Norton Engineering also provided input on recommended averaging times for each source category based on the initial proposed BARCT

NOx limits. Staff's final BARCT recommendations are reflective of Norton Engineering's comments. Norton Engineering's NOx BARCT Analysis Review can be found on the South Coast AQMD webpage.

Norton Engineering also conducted a review of the second cost submission submitted by the facilities on March 12, 2021, which was used by staff to revise the cost-effectiveness. Norton Engineering met with several technology vendors to understand the current state of both NOx combustion/source control and post-combustion control and is summarized in the table below. The table summarizes the most common techniques employed in controlling NOx emissions in refinery combustion equipment along with typical NOx levels that can be expected provided specific installation.

Table 2-38. Norton Engineering's Summary of NOx Control Techniques

Table 3.3-1: Assessment of NOx control technologies for proposed Rule 1109.1

Technology	New install applying BACT	Retrofit where the conditions are…			Comments
		Most favorable for the installation	Typical for the installation	Unfavorable for the installation	
Fuel switching to NG	% NOx reduction = 100 x {1 – 1 / [1 + 0.625 x (mol/mol H_2 before switch)] }				Approximation Independent of technology
FGR with staged fuel burner (1)	30 ppmv	> 30 ppmv	< 40 ppmv	< 50 ppmv	Typically applied to boilers
ULNB (1)	15 ppmv	< 20 ppmv	< 35 ppmv	< 50 ppmv	Commercially available ULNBs
Next generation ULNB (1)	> 5 ppmv		< 10 ppmv		Commercial demonstration underway with Clearsign
Flameless combustion (1)	5 ppmv	–	–	–	One demonstration unit on a small heater
SNCR with 5 ppmv NH_3 slip	70% NOx reduction maximum	High inlet NOx (>100 ppmv): 40 to 50% NOx reduction			Limited application due to geometrical considerations
		Low inlet NOx (50 to 100 ppmv): 20 to 40% NOx reduction			
SCR	2 ppmv	2 ppmv			Multiple catalyst beds required
Lo-TOx	10 ppmv	10 ppmv	≤ 90% NOx Reduction	< 50% NOx reduction	Wet Gas Scrubber (WGS) required downstream

(1) Fuel assumed to be RFG unless noted otherwise

Assessment of Control Technologies

Process Heaters and Boilers

Norton Engineering's assessment of control technologies coincides with staff's assessment that in some cases combination of source and post-combustion control are required to meet BARCT levels. Combination control is the most effective way of reducing NOx for the process heaters and boilers categories. Staff initially concluded that 2 ppmv NOx is technically feasible with a combination of LNB or ULNB and SCR, but Norton Engineering indicated that achieving a 2 ppmv NOx with just an SCR is also possible and will require the unit to:

- Operate at low superficial gas velocity (<10 ft/s),

- Operate within the optimal temperature window,
- Install multiple SCR catalyst beds (2 minimum) with an ammonia destruction bed, and
- Employ multiple ammonia injection grids between catalyst beds for uniform distribution of ammonia.

This recommendation by Norton Engineering was used by staff as an alternative pathway to achieve 2 ppmv NOx when stakeholders expressed concern over the ability of heaters to accept a ULNB retrofit. Staff also initially assumed that LNB can achieve 40 ppmv NOx and used that as the upper NOx limit when calculating cost-effectiveness. However, Norton Engineering's assessment concluded that under unfavorable conditions, an LNB can have NOx emissions up to 50 ppmv. Staff revised the cost-effectiveness calculation using 50 ppmv NOx as the upper limit for burner control technology.

Steam Methane Reformer (SMR) Heaters and SMR Heaters with Gas Turbine
For this heater category, staff relied on Norton Engineering's recommendation that the lowest BARCT limit that could be set is 5 ppmv NOx with the expectation that multiple SCR catalyst beds will be required in most cases. Norton Engineering stated that high hydrogen content in the fuel will result in high combustion zone temperature and fuel gas composition swings due to the pressure swing adsorption cycle can impact NOx.

Sulfuric Acid Plant Furnaces
Norton Engineering's conclusion for the sulfuric acid furnaces agrees with staff's conclusion. Both Norton Engineering and staff concluded that post-combustion options are not well suited for this application due to the high sulfur and low temperatures which can potentially form ammonium bisulfate and plug or foul the catalyst. LoTOx™ will require modification or additional changes to the existing scrubber system. Norton Engineering supports staff's proposed BARCT NOx limit of 30 ppmv with custom designed burners.

Fluid Catalytic Cracking Unit (FCCU)
Norton Engineering's assessment for the FCCU category concluded that staff's BARCT proposal of 2 ppmv NOx is technically feasible with a multi-bed SCR system. The FCCU regenerator operates at temperatures where thermal NOx formation is low and the primary source of NOx originates from nitrogen species in the feed, or coke on catalyst, which is analogous to fuel NOx. Heavily hydrotreating the feed to the FCCU can reduce nitrogen species in order to reduce NOx emissions. Other control options include regenerator catalyst additives that reduce NOx, which must be used in conjunction with SCR.

Gas Turbines (firing natural gas and other gaseous fuels)
NOx controls for gas turbines are dry low NOx (DLN) combustors and SCR. These are the two most effective NOx controls for gas turbines. Norton Engineering agrees that the BARCT NOx limit of 2 ppmv is achievable with new SCR designs and 50% more catalyst than the existing SCR.

Petroleum Coke Calciner
Norton Engineering's assessment agrees with staff's assessment that post-combustion control is the only practical solution for NOx reduction to the proposed BARCT limit for the petroleum coke calciner. The petroleum coke calciner has a high combustion zone with an adiabatic chamber, so source control options, such as LNB, are limited. Norton Engineering also identified three post-combustion control options that can be considered for the petroleum coke calciner:

1. SCR, which requires an optimal temperature 650 to 750 ºF and may require stack flue gas reheat with duct burners;
2. LoTOx™, which requires a wet scrubber and ozone generation equipment; and
3. UltraCat™, which has similar requirements as SCR, but has limited field usage and requires a large plot area.

Sulfur Recovery Units/Tail Gas (SRU/TG) Incinerators
Norton Engineering's assessment concludes that NOx emissions from SRU/TG incinerators are the result of NOx concentration in the inlet vapor. Norton Engineering agrees with staff's assessment that the only practical solution is advanced custom designed burner upgrades or retrofits which can achieve 30 ppmv NOx. Commercially available ULNB are not well suited for this application. SCR is impractical for this category due to low temperature and high SOx which can form ammonium bisulfate and foul the catalyst. LoTOx™ is a potential option if space is available downstream.

Averaging Times
Norton Engineering recommended a 24-hour averaging time for any unit with a CEMS. The 24 hour is recommended based on detection of meaningful fluctuation and time for operations to diagnose and resolve problems. Staff revised the proposed averaging times for units with CEMS based on the recommendation.

Fossil Energy Research Corporation Assessment
FERCo conducted site visits to the five major refineries, Chevron, Marathon (Tesoro Refinery), Phillips 66, Torrance, and Valero, to evaluate and discuss facility constraints and challenges of implementing SCR on specific refinery systems. The main concern refinery stakeholders frequently raised to staff was the issue of space and the ability to install post-combustion control. The goal of the FERCo facility visits was to observe first-hand these facility concerns. FERCo met with facility representatives and toured the facilities. In addition, FERCo and facility staff discussed any challenges of implementing SCR on specific refinery systems which included a review of drawings of on-going SCR work or suggested configuration modifications to improve performance. FERCo also assisted staff in the cost evaluation by evaluating the two main source of cost estimates: revised U.S. EPA SCR cost model and unit-specific costs from facilities. FERCo also reviewed staff's methodology in revising the U.S. EPA SCR cost model which involved using refinery specific cost data to modify the cost relationships making it more representative of the refining industry. FERCo's South Coast Air Quality Management District Rule 1109.1 Study Final Report can be found on the South Coast AQMD webpage.

Factors Affecting NOx Control Costs
Based on the site visits, FERCo concluded that all the facilities exhibited space limitations to varying degrees. Not all open space that surrounds a unit is available for an SCR system, as open space may be necessary for maintenance work. Despite the space limitations, some facilities have devised several workarounds such as vertical SCR orientation, running ductwork over existing roadways, and replacement of air heaters with SCR reactors. In addition, FERCo also identified that the locations or sites for SCR installations may hold many unknowns such as electrical capacity for the SCR and uncertainties that can complicate foundation work such as underground pipes. Based on these complexity factors, FERCo confirmed that the installation cost can significantly exceed that of the NOx equipment and can exceed the equipment cost by a factor of at least 2.5. Based on FERCo's assessment, staff has agreed to accept all facility provided cost

data in the cost-effectiveness analysis. If a facility provided cost for a specific unit, staff used the facility cost data. Furthermore, staff used all the facility cost to revise the U.S. EPA SCR cost model.

Upgrading Existing SCR Reactors

FERCo's assessment also determined that existing SCR systems are not designed for high NOx removal (>90% reduction), FERCo identified several key SCR issues that can be improved upon to achieve better performance:

- Catalyst activity or how active the material is in reducing NOx;
- Reactor potential, the ability of the catalyst bed to reduce NOx, and needed catalyst volume; and
- Ammonia/NOx distribution which describes the uniformity across the catalyst and mechanism by which ammonia is injected. This is characterized by root mean squared (RMS) or deviation of ammonia/NOx distribution entering the catalyst – higher NOx removal requires lower RMS.

FERCo also discussed the importance of AIG tuning in optimizing ammonia/NOx distribution by providing an example of a recent project where additional NOx reduction was achieved simply by tuning the system.

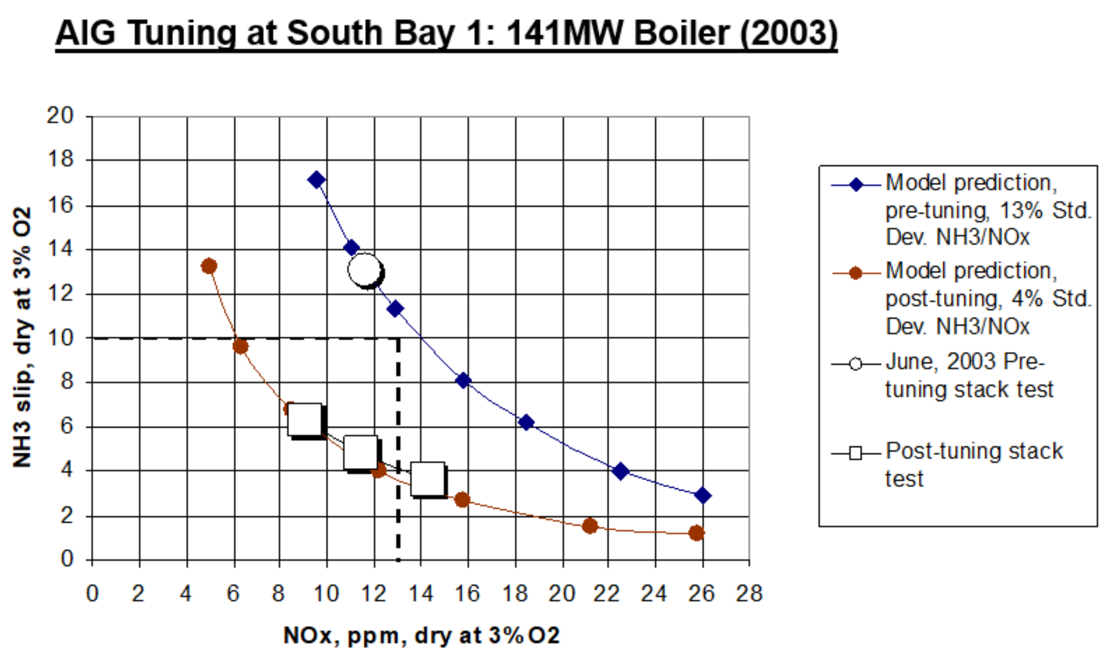


Figure 11. AIG Tuning Optimization

Changes to the AIG may include any of the following changes:

- Resizing existing AIG orifices
- Redesigning the AIG

- Adding flow control valves
- Moving AIG to different location
- Adding a static mixer

According to FERCo all these changes are relatively minor, involving at most piping modifications. Overall, upgrading of existing SCR systems to comply with Rule 1109.1 are estimated to cost between 10 and 35% of the cost of a new SCR. FERCo anticipates that only minor modifications will likely be needed since all the SCR infrastructure is already in place. FERCo also recommended that replacing or adding additional SCR catalyst can help improve removal efficiency. Staff has incorporated this recommendation in establishing the criteria for the conditional limits for units in the process heater and boilers category. These units will be allowed to upgrade their existing SCR system to reduce overall cost to a facility. It is more cost-effective to upgrade a SCR than replace with a brand-new system.

FERCo also stated that to further achieve maximum emission reductions, a combination of LNB/ULNB and SCR will be necessary for devices with high NOx emissions. FERCo also suggested that potentially splitting the SCR catalyst volume between two reactors in series (each housing to be equal to one-half of the total catalyst volume) where additional mixing of the flue gas stream could be accomplished.

U.S. EPA Cost Model

FERCo also reviewed staff’s approach to modifying the U.S. EPA SCR cost model and concluded that it can be used to provide budgetary costs. FERCo stated that the SCR cost model be improved by improving the methodology to estimate required catalyst volumes based on current catalyst technology available which is minor when compared to the overall installation costs.

CHAPTER 3 SUMMARY OF PROPOSALS

INTRODUCTION

PR 1109.1 establishes NOx and CO concentration limits for combustion equipment located at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. All the Facilities subject to PR 1109.1 are currently in RECLAIM and will be required to meet the limits in PR 1109.1 while in RECLAIM and after the facility transitions out of RECLAIM and becomes a Former RECLAIM Facility. The proposed rule includes provisions and requirements consistent with other NOx RECLAIM landing rules as well as provisions specific to Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. The following information describes the structure of PR 1109.1 and explains the requirements in each of the provisions.

PROPOSED RULE STRUCTURE

(a)	Purpose
(b)	Applicability
(c)	Definitions
(d)	Concentration Limits
(e)	Interim Concentration Limits
(f)	Compliance Schedule
(g)	B-Plan and B-Cap Requirements
(h)	I-Plan Requirements
(i)	I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements
(j)	Time Extensions
(k)	CEMS Requirements
(l)	Source Test Requirements
(m)	Diagnostic Emission Checks
(n)	Monitoring, Recordkeeping, and Reporting Requirements
(o)	Exemptions
(Attachment A)	Supplemental Calculations
(Attachment B)	Calculation Methodology for the I-Plan, B-Plan, And B-Cap
(Attachment C)	Facilities Emissions – Baseline and Targets
(Attachment D)	Units Qualify for Conditional Limits in B-Plan and B-Cap

PROPOSED RULE 1109.1

SUBDIVISION (a) – PURPOSE

The purpose of this rule is to reduce emissions of NOx, while not increasing CO emissions, from combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. As discussed in Chapter 1, PR 1109.1 is needed to transition Petroleum Refineries and Facilities With Related Operations to Petroleum Refineries from RECLAIM to a command-and-control regulatory structure. PR 1109.1 is a command-and-control rule that is designed to satisfy requirements to establish BARCT under Health and Safety Code Section 40920.6 which implements AB 617.

SUBDIVISION (b) – APPLICABILITY

PR 1109.1 applies to combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, including Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, Petroleum Refineries, facilities that operate Petroleum Coke Calciners, Sulfuric Acid Plants, and Sulfur Recovery Plants. The provisions of PR 1109.1 apply to Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries while in RECLAIM and after they transition out of RECLAIM. Combustion equipment which are subject to this rule are categorized as Boilers, Flares, Fluid Catalytic Cracking Units, Gas Turbines, Petroleum Coke Calciners, Process Heaters, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces, Sulfur Recovery Units/Tail Gas Incinerators, and Vapor Incinerators.

SUBDIVISION (c) – DEFINITIONS

Definitions in PR 1109.1 are incorporated to define equipment, fuels, and other rule terms. Below are some key definitions that are used in PR 1109.1. To provide clarity, definitions are used in the proposed rule and this staff report as a proper noun to better distinguish defined terms from common terms. Refer to PR 1109.1 for a complete list of definitions.

PR 1109.1 includes a definition for "Facilities With The Same Ownership" which is used in a couple of key provisions for alternative compliance plans and certain provisions for interim emission limits.

- FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

At the time of this staff report, the following are the PR 1109.1 Facilities With The Same Ownership:

Table 3-1. Facilities With The Same Ownership

Owner	Facility	Facility ID
Marathon Petroleum Company/Tesoro Refining and Marketing, LLC (Marathon)	Tesoro – Carson	174655
	Tesoro – Wilmington	800436
	Tesoro – Sulfur Recovery Plant	151798
	Tesoro – Petroleum Coke Calciner	174591
Phillips 66	Phillips 66 – Carson	171109
	Phillips 66 – Wilmington	171107
Valero	Ultramar/Valero Wilmington	800026
	Valero Asphalt Plant	800393

The definition of "Unit" was included to streamline the rule language.

- UNIT means, for the purpose of this rule, any Boilers, Flares, FCCUs, Gas Turbines, Petroleum Coke Calciners, Process Heaters, SMR Heaters, Sulfuric Acid Furnaces, SRU/TG Incinerators, or Vapor Incinerators that requires a South Coast AQMD permit and is not required to comply with a NOx concentration limit in another South Coast AQMD Regulation XI rule.

SUBDIVISION (d) – CONCENTRATION LIMITS

This subdivision establishes the proposed BARCT NOx Concentration Limits and Corresponding CO Concentration Limits for combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. PR 1109.1 Table 1 lists the NOx Concentration Limits and Corresponding CO Concentration Limits for each class and category of equipment subject to PR 1109.1 and identifies the corresponding rolling averaging time and percent of oxygen as the basis for emissions measurement or calculation. Averaging times must be calculated as established in Attachment A of PR 1109.1 for any unit that operates with CEMS. All averaging times based on CEMS are rolling averages and are established for different types of equipment in Table 1 and Table 2 of PR 1109.1. Units that must demonstrate compliance with a source test are required to demonstrate compliance based on the time specified in the approved source test protocol as discussed in subdivision (l). Subdivision (f) lays out the compliance dates for a Facility complying with the NOx and CO Concentration Limits in Table 1.

NOx CONCENTRATION LIMIT(S) means the NOx concentration limit at the applicable percent O_2 correction and averaging period specified in Table 1, Table 2, Table 3, or Table 5 – Maximum Alternative BARCT NOx Concentration Limits for a B-Cap (Table 5).

CORRESPONDING CO CONCENTRATION LIMIT(S) means the CO concentration limit, that corresponds to the referenced NOx Concentration Limit, at the applicable percent O_2correction and averaging period specified in Table 1, Table 2, or Table 3 – Interim NOx and CO Concentration Limits (Table 3).

Table 3-2. PR 1109.1 Table 1 – NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(B)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(C)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

Proposed NOx Limits for Boilers and Process Heaters with a Rated Heat Input Capacity Less than 40 MMBtu/hr – Paragraph (d)(2)

PR 1109.1 establishes NOx Concentration Limits for Boilers and Process Heaters less than 40 MMBtu/hr in two steps. The averaging time, oxygen correction, and Corresponding CO Concentration Limit are specified in Table 1 and is the same for the applicable NOx Concentration

Limits to these Units in both steps. The compliance schedule for the two steps is addressed under the Compliance Schedule in Table 4. The NOx Concentration Limit for Boilers and Process Heaters less than 40 MMBtu/hr is:

- First Step: 40 ppmv for both Boilers and Process Heaters; then
- Second Step: 5 ppmv for Boilers and 9 ppmv for Process Heaters.

Conditional NOx Concentration Limits – Paragraph (d)(3)
PR 1109.1 provides alternative BARCT NOx limits for units which are currently operating at or below NOx Concentration Limits in Table 2 of PR 1109.1, shown as Table 3-3 below. This provision is designed to recognize that some units have existing pollution controls that are currently operating near the NOx Concentration Limits in PR 1109.1 Table 1, and it is not cost-effective to require replacement or installation of additional pollution controls for those Units. PR 1109.1 includes conditions that an owner or operator must meet if an owner or operator elects to meet the Conditional NOx Concentration Limits and Corresponding CO Concentration Limits in Table 2, in lieu of the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1.

Table 3-3. PR 1109.1 Table 2 – Conditional NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters ≥40 – ≤110 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	2-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

PR 1109.1 allows owners or operators to use PR 1109.1 Table 2 Conditional NOx Concentration Limits in lieu of meeting Table 1 NOx Concentration Limits. The owner or operator must meet all of the conditions specified under paragraph (d)(3) and meet the permit submittal and compliance dates under paragraph (f)(3), including submitting a permit application by June 1, 2022.

Conditions for Using Conditional NOx Concentration Limits
Since the Table 2 NOx Concentration Limits can be used in lieu of Table 1 NOx Concentration Limits to establish the Facility BARCT Emission Target under the alternative BARCT compliance

plans, staff realized it was critical to establish conditions to ensure only those Units that were operating near the NOx Concentration Limits in Table 1 and would have high cost-effectiveness values to meet NOx Concentration Limits in Table 1 are allowed to use the Conditional NOx Concentration Limits. Staff was also concerned that owners or operators could potentially install pollution controls and meet the Conditional NOx Concentration Limits instead of the more stringent Table 1 NOx limits and could create a “budget” of NOx emissions that could be used to have higher NOx concentration levels for other Units.

Under subparagraph (d)(3)(A), the first condition for a unit to be allowed a Table 2 conditional limit is that the Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a pollution control device. This condition is to prevent Units with currently installed pollution control devices, such as SCR, which can achieve the Table 1 NOx Concentration Limits, from electing to comply with Table 2 conditional limits. December 4, 2015 was selected as this is the date when Regulation XX – RECLAIM was amended to reduce or shave allocations. The analysis was based on a technical analysis that large boilers and heaters could achieve a NOx concentration of 2 ppmv. Staff believes that Units modified after this date should have been designed to achieve the proposed NOx limits in Table 1. Boilers and heaters greater than or equal to 40 MMBtu/hour installed with a modern SCR can achieve 5 ppmv NOx, if not lower. This condition will also ensure Units that can achieve significant NOx reductions in a cost-effective manner, are required to meet the NOx and CO Concentration Limits under Table 1 of PR 1109.1.

The next two conditions, subparagraphs (d)(3)(B) and (d)(3)(C), are that emission reduction projects for Process Heaters greater than or equal to 40 MMBtu/hour but less than or equal to 110 MMBtu/hour cannot have an emission reduction potential (referred to in the rule as “Unit Reductions” and calculated pursuant to Attachment B in the rule) of 10 tons per year or more, and emission reduction projects for Boilers or Process Heaters greater than 110 cannot have an emission reduction potential of 20 tons per year or more. The potential emission reductions are based on the difference of the baseline emissions and the Table 1 concentration limits, scaled to the baseline emissions.

The next two conditions, subparagraphs (d)(3)(D) and (d)(3)(E), are that the Unit must not have an existing permit limit at or below the Table 1 NOx Concentration Limits or have a Representative NOx Concentration that is at or below the Table 1 NOx Concentration Limits. These conditions will prevent Units that are achieving NOx emissions that meet the Table 1 NOx Concentration Limits from electing to comply with the conditional limits.

FACILITY BARCT EMISSION TARGET means the total mass emissions per facility calculated based on the applicable Table 1 NOx emission limits or Table 2 conditional NOx limits and the 2017 annual NOx emissions, or another representative year as approved by the Executive Officer.

The last condition, subparagraph (d)(3)(F), excludes any unit that has been decommissioned pursuant to paragraph (f)(10) from being eligible to use the conditional NOx limits in Table 2.

Gas Turbines – Paragraph (d)(4)

PR 1109.1 provides an alternative NOx concentration limit of 5 ppmv (corrected to 15 percent oxygen on a dry basis) based on a 24-hour rolling average, instead of the 2-ppmv and 3-ppmv NOx limits for Gas Turbines operating on natural gas and refinery gas, respectively, during natural gas curtailment periods. Natural gas curtailment occurs when there is a shortage in the supply of pipeline Natural Gas due to limitations in the supply or restrictions in the distribution pipelines by the utility that supplies Natural Gas. A shortage in Natural Gas supply that is due to changes in the price of Natural Gas does not qualify as a Natural Gas curtailment. Corresponding CO Concentration Limits for the Gas Turbines subject to this provision are the same as listed in Table 1 and Table 2 of PR 1109.1.

Units With Combined Stacks – Paragraph (d)(5)

Paragraph (d)(5) requires Units With Combined Stacks to meet the most stringent applicable Table 1 or Table 2 NOx Concentration Limit. Below are the criteria to determine which requirements apply to Units With Combined Stacks if one or more of the Units fall in a different size category as follows:

- If multiple Units are combined:
  - One Unit is >110 MMBtu/hr and the other are less → >110 MMBtu/hr
  - All Units are ≥40 – 110 MMBtu/hr → ≥40 – ≤110 MMBtu/hr
  - One Unit is ≥40 MMBtu/hr and the other Units are less → ≥40 – ≤110 MMBtu/hr

CO Concentration Limits – Paragraph (d)(6)

PR 1109.1 Table 1 and Table 2 establish CO concentration limits for each class and category of equipment. As discussed, the purpose of this rule is to reduce emissions of NOx from combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, with no increase in the associated CO emissions. The CO emissions for the classes and categories of equipment listed in PR 1109.1 Table 1 and Table 2 are generally representative of CO concentration limits in permits and consistent with other rules regulating similar combustion equipment. This paragraph allows an owner or operator of a Unit that has a CO concentration limit established in a Permit to Operate or Permit Construct before the date of rule adoption, to meet the CO concentration limit in the Permit to Operate or Permit to Construct in lieu of the applicable Corresponding CO Concentration Limit. The CO permit limit can include an actual permit limit or a reference to South Coast AQMD Rule 407 – Liquid and Gaseous Air Contaminants.

An owner or operator with six or more units, have the option to use a B-Plan or B-Cap that will allow the selection of a NOx limit that may be higher than the NOx limits established in PR 1109.1. However, regardless of the NOx limit selected in a B-Plan or B-Cap, the owner or operator is required to meet the applicable CO concentration limit in Table 1 or Table 2, or as allowed under paragraph (d)(6).

SUBDIVISION (e) – INTERIM CONCENTRATION LIMITS

As discussed in Chapter 2, Interim NOx Concentration Limits are needed after Facilities transition out of RECLAIM and before the Unit meets the NOx limits in PR 1109.1 to ensure there is no backsliding and interference with attainment.

Interim NOx Concentration Limits (e)(1)

The interim NOx Concentration Limits in of PR 1109.1 applies to Facilities that elect to meet the Table 1 or Table 2 NOx Concentration Limits directly, all Units at a Facility that is complying with a B-Plan, and any Boiler or Process Heater less than 40 MMBtu/hour not included in a B-Cap. The approach for the interim Concentration Limits is different for owners or operators that select to comply with a B-Plan versus complying with a B-Cap. Owners or Operators that elect to comply with a B-Plan will be required to meet equipment specific interim NOx Concentration Limits or NOx emission rates. On the other hand, the owners or operators that elect to comply with the B-Cap are not held to the individual interim NOx Concentration Limits since those Facilities are operating under a facility-wide mass emissions cap. However, any Units outside of the B-Cap will be required to meet the interim NOx Concentration Limits upon exiting RECLAIM, before being subject to another NOx limits in PR 1109.1. The provision for the B-Cap is needed as PR 1109.1 allows operators to exclude Boilers and Process Heaters less than 40 MMBtu/hour from the B-Cap. Any unit that is not included in the mass emissions cap under the B-Cap, will be required to meet the Interim NOx Concentration limit under Table 3 of PR 1109.1 upon exiting RECLAIM.

Interim NOx and CO Concentration Limits – Table 3

PR 1109.1 includes interim NOx Concentration Limits that are based on permit limits and actual emissions data. Except for interim NOx Concentration Limits for Boilers and Process Heaters 40 MMBtu/hour and greater, all interim limits are a specific NOx concentration limit and are provided in Table 3 of PR 1109.1 and are presented below. All interim limits provide a 365-day averaging period which is proposed to minimize disruptions as Facilities transition out of RECLAIM.

Table 3-4. PR 1109.1 Table 3 – Interim NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <6 MMBtu/hour[2]	60	400	3	365-day
Boilers and Process Heaters ≥6 MMBtu/hour and <40 MMBtu/hour[2]	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraph (e)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciner	85	2,000	3	365-day
SMR Heaters	20[3]	400	3	365-day
	60[4]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	110	400	3	365-day

1 Averaging times are applicable to Units with a CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

2 Boilers and Process Heaters with a Rated Heat Input Capacity <40 MMBtu/hour that operate with a certified CEMS may comply with the NOx emission rate pursuant to paragraph (e)(2) in lieu of the NOx Concentration Limit in Table 3.

3 SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [DATE OF ADOPTION].

4 SMR Heaters not equipped with post-combustion air pollution control equipment as of [DATE OF ADOPTION].

Interim Limits for Boilers and Process Heaters for Facilities Complying with Table 1 or Table 2, or a B-Plan – Paragraph (e)(2)

For Boilers and Process Heaters with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour, staff found substantial variation in the NOx concentration levels with no definitive groupings of Units to establish a specific NOx concentration limit. For owners or operators under an approved B-Plan, upon exiting RECLAIM when the facility becomes a Former RECLAIM Facility, the owner or operator must meet a 0.03 pounds/MMBtu over a rolling 365-day average for all Boilers and Process Heaters that are greater than or equal to 40 MMBtu/hour and may include Boilers and Process Heaters that are less than 40 MMBtu/hour if they operate with a certified NOx CEMS. This provision would be effective on the day after the Facility becomes a Former RECLAIM Facility and calculated per Attachment A Section (A-2) of PR 1109.1. To demonstrate the rolling average the owner or operator will use the mass emissions from the prior 365 days, with emissions for 364 days to be based on emissions while the Facility was in RECLAIM and emissions for the 365th day will be based on the day the Facility became a Former RECLAIM facility. Subparagraph (e)(2)(B) requires subparagraph (e)(2)(A) to be implemented until the last Unit under this provision meets the final applicable NOx concentration limit in Table 1, Table2, or an approved B-Plan to ensure that as Units comply with the NOx concentration limit, the remaining units do not exceed the applicable threshold.

The calculation to determine a Facility's NOx levels is included in Attachment A Section (A-2) of PR 1109.1 and is as follows:

- Hour Mass Emissions (lbs/hour) Section (A-2.1)

  Sum the actual annual mass emissions of all Boilers and Process Heaters with a Rated Heat Input Capacity at or greater than 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity less than 40 MMBtu/hour that operate a certified CEMS and divide by 8,760 hours for pounds per hour.

- Combined Maximum Rated Heat Input Capacity (MMBtu/hour) Section (A-2.2)

  Sum the combined maximum Rated Heat Input Capacity for all Boilers and Process Heaters with a Rated Heat Input Capacity at or greater than 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity less than 40 MMBtu/hour that operate a certified CEMS.

- Interim Facility Wide NOx Emission Rate (lbs/MMBtu) Section (A-2.3)

  Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim facility-wide NOx emission rate.

Interim Requirements for a Facility with a B-Cap – Paragraph (e)(3)

Facilities that elect to comply with a B-Cap will not be held to the NOx concentrations limits in Table 3 of PR 1109.1, with the exception of those Boilers and Process Heaters less than 40 MMBtu/hour that are not included in an approved B-Cap. Facilities under a B-Cap will be required to demonstrate on a daily bases, based a 365-day rolling average that they meet the Facility BARCT Emission Targets that are specified in subparagraph (h)(4)(D). If a facility exits RECLAIM before the implementation of the first Phase of an I-Plan, the emissions cap will be based on the Baseline NOx Emissions.

SUBDIVISION (f) – COMPLIANCE SCHEDULE

This subdivision establishes the implementation schedules for combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries to comply with PR 1109.1 requirements.

Compliance Schedule for Table 1 – Paragraph (f)(1)

This paragraph requires an owner or operator to submit a complete permit application to establish a NOx and Corresponding CO Limit in a permit on or before July 1, 2023. Owners or operators must meet the NOx and CO concentration limits in PR 1109.1 Table 1 from the date the Permit to Operate is issued or no later than 36 months after a Permit to Construct is issued, whichever is sooner. Operators with a Permit to Construct or a Permit to Operate that already has an enforceable NOx concentration limit consistent with Table 1 are not required to submit a permit application. This is the only compliance pathway for Facilities with less than six Units. For Facilities with six or more Units, PR 1109.1 provides this compliance pathway as well as an alternative implementation schedule under the I-Plan.

It should be noted several of the rule provisions require "a complete permit application" to be submitted. A complete permit application includes, but not limited to, all signed forms with all applicable fields filled in, applicable fees, and additional information needed by the Executive Officer to make a determination. This is different than a permit that has been "deemed complete", which is the formal determination the Engineering Division makes when confirming all information has been received to properly conduct their analysis to process the permit. There are existing rules which dictate the criteria for a complete permit application:

1. The preamble to Reg. II – List and Criteria Identifying Information Required Of Applicants Seeking A Permit To Construct From The South Coast Air Quality Management District;
2. Rule 210 – Permit to Construct; and
3. Rule 3003 – Applications.

A complete permit application includes, but is not limited to, all signed forms with all applicable fields filled in, applicable fees, and additional information needed by the Executive Officer to make a determination. PR 1109.1 includes the phrase "complete permit application" to ensure the Facilities submit all required information in order for the South Coast AQMD to meet the tight timelines and issue the plans and permits in a timely manner.

Compliance Schedule for Boilers and Process Heaters Less Than 40 MMBtu/hour – Paragraph (f)(2)

The NOx limit of 40 ppmv for Boilers and Process Heaters less than 40 MMBtu/hour is lowered to 5 ppmv for Boilers and 9 ppmv for Process Heaters when the owner or operator either cumulatively replaces 50 percent or more of the burners or the burners replaced cumulatively represent 50 percent or more of the Heat Input. The cumulative burner replacement provisions apply from a specified date to prevent a facility from replacing burners incrementally over time in order not to trigger a retrofit. The compliance schedule to achieve the two-step NOx Concentration Limits are provided in Table 4 of PR 1109.1, provided as Table 3-6 below. Additionally, owners or operators are required to maintain records for burner replacement for these boilers and process heaters to track burner replacement.

Boilers Less than 40 MMBtu/Hour

The first NOx Concentration Limit for Boilers less than 40 MMBtu/hour, pursuant to subparagraph (d)(2)(A), is 40 ppmv. Complete permit applications must be submitted by July 1, 2022, and the compliance date begins when South Coast AQMD issues the Permit to Operate as all of these units are currently achieving less than 40 ppmv NOx.

The second NOx Concentration Limit is 5 ppmv pursuant to subparagraph (d)(2)(B). The complete permit applications are due based on burner replacement and is due no later than six months from the either when 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input, with the cumulative replacement of burners beginning to be effective from July 1, 2022. The Boiler will be required to meet the 5 ppmv NOx limit 18 months from the date the Permit to Construct is issued by South Coast AQMD.

Process Less than 40 MMBtu/Hour

The first NOx Concentration Limit for these Process Heaters less than 40 MMBtu/hour, pursuant to subparagraph (d)(2)(A), is 40 ppmv and complete permit applications must be submitted by July 1, 2023. The compliance date begins when South Coast AQMD issues the Permit to Operate or 18 months from the date the Permit to Construct is issued by South Coast AQMD, whichever is sooner. Additionally, Facilities have the option to immediately meet the second step NOx concentration limit of 9 ppmv. For these Facilities, the compliance date will be 36 months from the date the Permit to Construct is issued by South Coast AQMD. PR 1109.1 includes a longer compliance schedule to implement the lower NOx limit to incentivize early adoption of the emerging technologies.

The second NOx Concentration Limit is 9 ppmv pursuant to subparagraph (d)(2)(C). Since the emission reduction technologies for Process Heaters are based on emerging technologies, the NOx limit of 9 ppmv is effective ten years after rule adoption to provide time for the emerging technologies to further develop. The complete permit applications are due based on burner replacement, no later than six months from the either when 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input, with the cumulative replacement of burners beginning to be effective beginning five year after rule adoption with the compliance date will be 18 months from the date the Permit to Construct is issued by South Coast AQMD. Most, but not all, Process Heaters less than 40 MMBtu/hour are currently achieving the first 40 ppmv NOx limit; however, several Units will have to be retrofit. The five-year time allowance to begin counting the cumulative burner replacement is to address the time needed to retrofit those units to meet the 40 ppmv NOx limit.

Staff believes that implementation of the B-Plan and B-Cap will help incentivize owners or operators to accelerate introduction and commercialization of emerging technologies. Staff will monitor the development of the emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized.

Table 3-5. PR 1109.1 Table 4 – Compliance Schedule for Boilers and Process Heaters Less Than 40 MMBtu/Hour

Unit	NOx Concentration Limit (ppmv)	Permit Application Submittal Date	Compliance Date
Boilers <40 MMBtu/ hour	40 ppmv pursuant to subparagraph (d)(2)(A)	On or before July 1, 2022	• On and after the date the South Coast AQMD issues a Permit to Operate
	5 ppmv pursuant to subparagraph (d)(2)(B)	Pursuant to subparagraph (f)(2)(B)	• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct
Process Heaters <40 MMBtu/ hour	40 ppmv pursuant to subparagraph (d)(2)(A)	On or before July 1, 2023	• On and after the date the South Coast AQMD issues the Permit to Operate or on and after 18 months from the date the South Coast AQMD issues a Permit to Construct, whichever is sooner; or • On and after 36 months from the date the South Coast AQMD issues a Permit to Construct if the owner or operator of a Facility elects to meet the NOx concentration limit pursuant to subparagraph (d)(2)(C) in lieu of subparagraph (d)(2)(A)
	9 ppmv pursuant to subparagraph (d)(2)(C)	Pursuant to subparagraph (f)(2)(C)	• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct

Compliance Schedule for Table 2 Conditional Limit – Paragraph (f)(3)

PR 1109.1 allows an owner or operator that meets the conditions specified in paragraph (d)(3) to elect to meet Conditional NOx and Corresponding CO Concentration Limits in Table 2 in lieu of Table 1 Limits. If Facilities use this option, they must submit a complete permit application on or before June 1, 2022 to establish a condition to limit the NOx and CO emissions to a level not to exceed the applicable Table 2 Conditional NOx and Corresponding CO Concentration Limits and meet that limit no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner. Staff is proposing 18 months to meet the NOx concentration limit since the conditional limits were intended for those Units that are currently achieving NOx levels that are near the Table 2 limits and little to no physical modifications to the Unit are needed. Staff is proposing June 1, 2022 to provide lead time prior to the submittal of an I-Plan, B-Plan, and B-Cap. A commitment that an owner or operator will be meeting the conditional NOx limit is needed to allow an owner or operator to account for a Unit that is seeking compliance with Table 2 in lieu of Table 1 NOx limits when calculating the Facility BARCT Emission Target. Implementation of the conditional limits by requiring a permit application by July 1, 2022 will help to expedite BARCT implementation consistent with AB 617.

Modifications to Existing Units that are Meeting Table 2 Conditional NOx Concentration Limits – Paragraph (f)(4)

Paragraph (f)(4) includes provisions for owners or operators that significantly modify existing pollution controls on a Unit that were previously meeting the Table 2 Conditional NOx and Corresponding CO Concentration Limits. Under subparagraph (f)(4)(A), an owner or operator meeting the Table 2 Conditional NOx and Corresponding CO Concentration Limits will be required to submit a complete permit application prior to replacing the exiting NOx control equipment to accept the NOx Concentration Limit and Corresponding CO Concentration Limit in Table 1 if replacing: (1) an existing with a new post-combustion air pollution control equipment; (2) components of existing post-combustion air pollution control equipment; and (3) burners for Vapor Incinerators.

Clauses (f)(4)(A)(i) and (f)(4)(A)(ii), include provisions for replacement of existing post-combustion controls or the replacement of components of post-combustion controls applies to FCCUs, Gas Turbines fueled with Natural Gas, Process Heaters with a Heat Input Capacity at or greater than 40 MMBtu/hour, and SMR Heaters. Additionally, the provision for replacing components, clause (f)(4)(A)(ii), applies if the cost of the components being replaced is greater than 50 percent of the fixed capital cost that would be required to construct and install new post-combustion air pollution control equipment. Clause (f)(4)(A)(ii), applies to burner replacement for vapor incinerators, where replacement is based on if 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input Capacity, where the cumulative replacement begins on rule adoption. This provision is to ensure if an owner or operator is making a significant modification to the listed equipment, the owner or operator will then be required to meet the Table 1 NOx and Corresponding CO Concentration Limits. Under subparagraph (f)(4)(B), the owner or operator must meet the Table 1 NOx Concentration Limit and Corresponding CO Concentration Limit no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner.

Exempted Units – Paragraph (f)(5)

Paragraph (f)(5) requires owners or operators with Units that are exempt pursuant to PR 1109.1 paragraphs (o)(2), (o)(3), (o)(5), (o)(6), (o)(8) and (o)(9) to submit a complete permit application by July 1, 2022 to meet the applicable limits required by the exemption. The applicable limits for the exemptions are as follows:

- Paragraphs (o)(2) and (o)(5), hours of operation per calendar year;
- Paragraph (o)(3), Rated Heat Input Capacity per calendar year;
- Paragraph (o)(6), Heat Input per calendar year; and
- Paragraphs (o)(8) and (o)(9), pounds of NOx per calendar year.

Exempted Units Exceeding Limits – Paragraph (f)(6)

Certain Units are exempt from the NOx and Corresponding CO Concentration Limits in Table 1, but have different applicable limits (e.g., hours of operation per calendar year or pounds of NOx per calendar year). Paragraph (f)(6) includes provisions for an owner or operator that exceeds the limits in required by the exemption. A complete permit application to meet the applicable NOx and Corresponding CO Concentration Limit in Table 1 must be submitted within six months of the exceedance. The deadline to comply with the Table 1 limits is no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner. Any unit that was exempt, and exceeds a limit is no longer exempt, cannot be included in B-Plan, B-Cap, or I-Plan and must comply with Table 1 limits.

Failure to Submit a Permit Application – Paragraph (f)(7)

Paragraph (f)(7) includes provisions for an owner or operator that fails to submit a permit application on time. This provision is to ensure that if an owner or operator submits a permit application late, the owner or operator will not be afforded additional time to meet the NOx and Corresponding CO limit. Under this provision, if an owner or operator fails to submit a permit application by the deadline in PR 1109.1, the owner or operator shall meet the applicable NOx Concentration Limit either 36 or 24 months from when the permit application is submitted, as compared to when the permit to construct is issued for most provisions under PR 1109.1. This provision is designed to strongly discourage late submittals of permit applications.

Provisional Averaging Time – Paragraph (f)(8)

During the rulemaking process some owners or operators commented that achieving the shorter averaging times and lower NOx Concentration Limits in PR 1109.1 will be challenging as owners or operators are currently accustomed to an annual compliance cycle under the RECLAIM program. Achieving the PR 1109.1 NOx Concentration Limits in Table 1 and Table 2 will require shorter compliance periods for all Units other than the FCCUs, Petroleum Coke Calciners, and Sulfuric Acid Plants, which will be subject to 365-day rolling averages. To address this additional challenge, for Units with an approved CEMS and subject to a rolling average less than 365 days, compliance with the NOx Concentration Limits or Alternative BARCT NOx Limits, and Corresponding CO Concentration limits must be demonstrated six months after the issuance of the Permit to Operate, 36 months after the Permit to Construct is issued, or immediately after completion of a compliance demonstration source test, whichever is soonest. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.

Initial Averaging Time for Units with a 365-Day Averaging Time Period – Paragraph (f)(9)

An owner or operator of a Unit subject to a 365-day rolling average shall demonstrate compliance with the applicable NOx Concentration Limit or Alternative BARCT NOx Limit beginning 14 months after the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or immediately after completion of a compliance demonstration source test, whichever is soonest. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.

Decommissioned Units – Paragraph (f)(10)

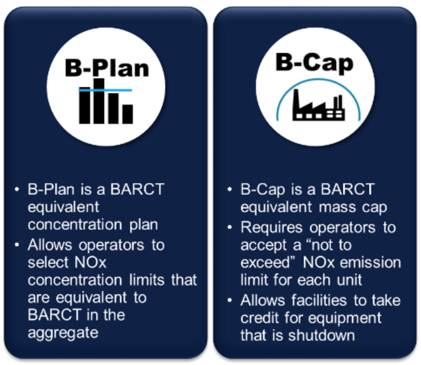
Units that will be decommissioned to comply with this rule will need to: 1.) surrender the Unit's Permit to Operate; 2.) disconnect and blind the Unit's fuel lines; and 3.) not sell the Unit for operation within the South Coast Air Basin.

The compliance schedule for decommissioned Units is dependent on which plan the Facility elects.

- If the Unit is excluded from a B-Plan, then the owner or operator shall comply within 54 months from the Phase I Permit Application Submittal Date specified in Table 6 for the I-Plan option selected.
- If an approved B-Plan is modified to remove a Unit that will be decommissioned, then the owner shall comply by the date specified by the Executive Officer.

- If a New Unit is replacing an entire or part of a decommissioned Unit to meet the requirements of an approved B-Cap and an approved I-Plan, then owner or operator shall comply within 90 days from commissioning a New Unit.
- If a Unit is to be decommissioned and not being replaced with a New to meet the requirements of an approved B-Cap and an approved I-Plan, then owner or operator shall comply no later than the B-Cap Effective Date of the Facility BARCT Emission Target specified in Table 6 for the I-Plan option selected for a B-Cap.

SUBDIVISION (g) – B-PLAN AND B-CAP REQUIREMENTS



PR 1109.1 includes two alternative compliance options to directly meeting the NOx Concentration Limits in Table 1 or Table 2 for owners or operators with six or more Units. These alternative compliance options were developed to address the complexity of operations at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, recognizing that achieving the Table 1 NOx Concentration Limits may be more challenging for some Units, as owners or operators are integrating new pollution control equipment on existing Units within the existing configuration of their Facility. The B-Plan is a BARCT Equivalent Compliance Plan and is designed to achieve the NOx and CO Concentration Limits in Table 1 and Table 2, in aggregate. The B-Cap is a BARCT Equivalent Mass Cap Plan and is designed to achieve the NOx Concentration Limits in Table 1 and Table 2, based on aggregate mass emissions. Both the B-Plan and B-Cap are designed to achieve similar NOx emission reductions as if owners or operators were directly complying with Table 1 and Table 2 NOx and CO Concentration Limits.

Paragraphs (g)(1) and (g)(2) establish the requirements for the B-Plan and B-Cap, respectively. Owners or operators that elect to use an alternative compliance option, must select either the B-Plan or the B-Cap and submit the plan on or before September 1, 2022. Both the B-Plan and the B-Cap require owners or operators to submit a permit application to limit the NOx concentration to the selected Alternative BARCT NOx Limit for each Unit. Implementation of projects to achieve the Alternative BARCT NOx Limit in the B-Plan and the B-Cap are based on the schedule in the approved I-Plan. At full implementation, all Units regulated under PR 1109.1 will have an enforceable NOx concentration permit limit.

Requirements for the B-Plan - Paragraph (g)(1)

Under the B-Plan, owners or operators select an Alternative BARCT NOx Limit for each Unit. If the owner or operator can meet the conditions of the Conditional NOx Concentration Limits under paragraph (d)(3), the Alternative BARCT NOx Limit cannot exceed the Table 2 NOx Concentration Limit, with the exception of any Unit identified in Table D-1 of PR 1109.1. Pursuant to paragraph (d)(3), a Unit listed on Table D-1 is not limited to the NOx concentration limits in Table 2 and the owner or operator can submit complete permit applications for these Units based on the established Alternative BARCT NOx Limits in the approved I-Plan.

BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator of a Facility to select Alternative BARCT NOx Limits for all Units subject to the B-Plan that will achieve emission reductions that are greater in the aggregate than the mass emission reductions that would be achieved based on the NOx Concentration Limits in

An owner or operator that elects to meet the Table 1 and Table 2 NOx Concentration Limits and Corresponding CO Limits through implementation of a B-Plan is required to:

- Submit a B-Plan on or before September 1, 2022;
- Identify all Units subject to the Rule 1109.1 B-Plan
- Select an Alternative BARCT NOx Limit for each Unit and calculate the BARCT Equivalent Mass Emissions, with specific requirements for Units meeting the Conditional NOx Concentration Limits; and
- Not include any Unit that has been or will be decommissioned.

Units to be Included in the B-Plan – Subparagraph (g)(1)(B)

Under the B-Plan, all Units are to be included in the B-Plan with a few exceptions. Pursuant to subparagraph (g)(1)(B) Units that can be excluded include Optional Units, which are Boilers or Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour that will meet the NOx concentration limits pursuant to subparagraph (d)(2)(B) or (d)(2)(C); Units that will be decommissioned 54 month from the permit submittal date of Phase I of the selected I-Plan, and some units that are exempt from the NOx Concentration Limits in Table 1 because they are low use under paragraphs (o)(2) (low-use boilers < 40 MMBtu/hr), (o)(5) (FCCU boilers or process heaters operating less than 200 hours per year), (o)(6) (startup or shutdown boilers and process heaters using less than 90,000 MMBtu annually), (o)(8) (flares that emit ≤ 550 of NOx per year, and (o)(9) (vapor incinerators emitting less than 100 pounds of NOx per year for unlimited exemption or less than 1,000 pound of NOx per year for limited exemption), and Units listed under paragraph (o)(1) (boilers or process heaters ≤ 2 MMBtu/hr used for comfort heating) shall not be included in the B-Plan. Any Unit that has been decommissioned should not be included in the B-Plan.

With regard to the B-Plan, in communication with U.S. EPA, the B-Plan will result in an environmental benefit by requiring BARCT Equivalent Mass Emissions, based on Alternative BARCT limits, to be less than (not equal to) the Facility BARCT Emission Target, which is derived from applicable BARCT NOx limits in Table 1 and Table 2. In addition, the B-Plan does not allow shutdowns and the Alternative BARCT NOx limits used in the B-Plan are either at or below RACT.

Calculating the BARCT Equivalent Mass Emissions -Subparagraph (g)(1)(C)
The methodology for calculating the BARCT Equivalent Mass Emissions is presented in Attachment B. Subparagraph (g)(1)(C) specifies parameters for the NOx concentration values that must be used in this calculation. The operator is responsible for selecting the Alternative BARCT NOx Limit and identifying which phase that the Alternative BARCT NOx Limit will be implemented. For an I-Plan, for any Unit that meets the conditions for Table 2 NOx Concentrations because the operator has submitted a permit application by June 1, 2022, must limit the Alternative BARCT NOx Limit to Table 2 NOx Concentrations. This provision clarifies that any Unit where the Alternative NOx BARCT Limit has not yet been identified for a phase of the I-Plan, that the Representative NOx Concentration which would be representative of the Baseline NOx Emissions will be used to calculate the BARCT Equivalent Mass Emissions and is for the purpose calculating the BARCT Equivalent Mass Emissions. This section also requires that the operator demonstrate that by the final phase of the I-Plan, each Unit will be assigned an Alternative BARCT NOx Limit.

Implementation of an Approved B-Plan – Paragraph (g)(2)

Paragraph (g)(2) establishes the requirements after approval of an I-Plan and B-Plan pursuant to paragraph (i)(4). After an owner or operator receives approval of an I-Plan and B-Plan, the operator is required to submit a complete Permit application to apply for a condition that limits the NOx limits not to exceed the Alternative BARCT NOx Limit and Corresponding CO Limits based on the schedule in the approved I-Plan. An operator must not operate a Unit unless the NOx and CO concentration levels are below the Alternative BARCT NOx Limits. By the final implementation phase in the I-Plan, an Alternative BARCT NOx Limit must be identified for each Unit in the I-Plan, where the permit application submittal is based on the dates in approved I-Plan. An Alternative BARCT NOx Limit is required for all Units in the I-Plan, regardless of if the Unit is modified to add pollution controls. This ensures that each Unit has an enforceable NOx concentration limit for each Unit in the I-Plan.

Requirements for the B-Cap - Paragraph (g)(3)

Under the B-Cap, the requirements are the same as for an operator that elects to use a B-Plan for the provisions listed above, with the exception of provisions for using Table 2 Conditional Limits. Since decommissioned Units are allowed under the B-Cap the provision to remove a Unit that will be decommissioned within Phase I is not included in the B-Cap. In addition, there are additional provisions for the B-Cap to provide safeguards to ensure the B-Cap remains equivalent to Table 1 and Table 2 NOx Concentration Limits based on aggregate mass emissions. These additional provisions are discussed below.

B-CAP means a compliance plan that establishes a Facility mass emission cap for all units subject to the B-Cap that, in the aggregate, is less than the Final Phase Facility BARCT Emission Target.

Calculating the BARCT Equivalent Mass Emissions - Subparagraph (g)(3)(C)
The methodology for calculating the BARCT Equivalent Mass Emissions is presented in Attachment B. Subparagraph (g)(3)(C) specifies parameters for the NOx concentration values that must be used in this calculation. The provisions are identical to the B-Plan, with one additional criteria that while the Representative NOx Concentration may exceed Maximum Alternative BARCT NOx Concentration Limits in Table 5, however, the Alternative NOx BARCT Limit cannot exceed the Maximum Alternative BARCT NOx Concentration Limits for a B-Cap pursuant

to Table 5 of PR 1109.1. Similar to the discussion for the B-Plan, the use of the Representative NOx Concentration is for calculating the BARCT Equivalent Mass Emissions.

Table 3-6. PR1109.1 Table 5 – Maximum Alternative BARCT NOx Concentration Limits for a B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SMR Heaters	12 ppm	3	24-hour
SRU/TG Incinerators	100 ppmv	3	24-hour
Vapor Incinerators	40 ppmv	3	24-hour

1 Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

Calculating the BARCT B-Cap Annual Emissions – Subparagraph (g)(3)(D)

Under the B-Cap, operators have three mechanisms to reduce mass emissions: (1) Lower the NOx concentration level of the Unit; (2) decommissioning units, and (3) implement other emission reduction strategies such as reduced throughput, capacity, or any other emission reduction strategy that would lower mass emissions. Under the B-Cap, operators can use any of the three emission reduction strategies to reduce mass emissions from Units in the B-Plan but must also demonstrate daily that actual emissions are below the Facility BARCT Emission Target based a rolling 365-day average. In addition, the Facility BARCT Emission Target is based on Table 1 and Table 2 NOx Concentration Limits, plus an additional 10 percent reduction to benefit the environment. This is a 10 percent reduction in NOx, that operators that use a B-Cap are required to achieve. The 10 percent environmental benefit is included to meet U.S. EPA guidelines for economic incentive programs. U.S. EPA views the B-Cap as an economic incentive program as it allows trading of emission reductions within a facility emissions cap and allows the use of reductions from decommissioned Units to meet emission reduction obligations. For a more detailed discussion of the 10 percent environmental benefit, refer to the section on Subdivision (h) of PR 1109.1 in this Staff Report.

BARCT B-CAP ANNUAL EMISSIONS means the sum of the mass emissions from the Unit B-Cap Annual Emissions for each phase of an I-Plan, that is based on the Alternative BARCT NOx Limits, decommissioned Units, and other emission reduction strategies to meet the Facility BARCT Emission Targets in an I-Plan as calculated pursuant to Attachment B of this rule.

Implementation of a B-Cap – Paragraph (g)(4)

Paragraph (g)(4) establishes the requirements after approval of an I-Plan and B-Cap pursuant to paragraph (i)(4). After an owner or operator receives approval of an I-Plan and B-Plan, the operator is required to submit a complete Permit application to apply for a condition that limits the NOx limits not to exceed the Alternative BARCT NOx Limit and Corresponding CO Limits based on the schedule in the approved I-Plan.

Not Operate a Unit above the Alternative BARCT NOx Limit – Subparagraph (g)(4)(B)
Subparagraph (g)(4)(B) specifies that a Unit cannot exceed the Alternative BARCT NOx Limit based on the schedule in the approved I-Plan. By the final implementation phase in the I-Plan, an Alternative BARCT NOx Limit must be identified for each Unit in the I-Plan, where the permit application submittal is based on the dates in approved I-Plan. An Alternative BARCT NOx Limit is required for all Units in the I-Plan, regardless of if the Unit is modified to add pollution controls. This ensures that each Unit has an enforceable NOx concentration limit for each Unit in the I-Plan.

Decommissioned Units Under the B-Cap – Subparagraph (g)(4)(C)
Under the B-Cap, an operator can permanently decommission a Unit to meet the Facility BARCT Target since emissions from all units are "capped" and the facility is meeting BARCT based on mass emissions. The owner or operator of a Unit that elects to decommission a Unit under a B-Cap is required to reflect the emissions from the decommissioned unit as Table 1 emissions in the Final Phase Facility BARCT Emission Target. For any Unit that is decommissioned, the South Coast AQMD Permit to Operate must be surrendered, and the owner shall disconnect and blind the fuel line(s) to the unit and not sell the unit for operation to another entity within the South Coast Air Basin. Provisions for decommissioning a Unit and the schedule to decommission a Unit are discussed under paragraph (f)(10).

Daily Demonstration that Units in the B-Cap are Below the Facility BARCT Emission Target – Subparagraph (g)(4)(D)
It is expected that operators that are using a B-Cap will have higher Alternative BARCT NOx Concentration Limits for each individual Unit compared to Units under the B-Plan. However, the B-Cap has two additional safeguards to address this issue. The first provision limits the Alternative BARCT NOx Concentration Limits to ensure that each Unit has pollution controls (subparagraph (g)(4)(B)). Under PAR 1109.1, the Alternative BARCT NOx Limits cannot exceed the Maximum Alternative NOx Concentration Limits in Table 5 of PR 1109.1. The second provision is the mass emissions cap, and the daily demonstration that operators are below the Facility BARCT Emission Target based on a rolling 365-day average (subparagraph (g)(4)(D)). This ensures that although some Units will individually have higher Alternative BARCT NOx Concentration Limits the operation of these, and all Units cannot exceed the mass emissions cap. Although Alternative NOx Concentrations may be higher than those under a B-Plan and the B-Cap some additional flexibilities such as the use of decommissioned Units and other emission reduction strategies, this second compliance component ensures that mass emissions, based on an annual average, are representative of the Units meeting Table 1 and Table 2 NOx Concentration Limits. It should also be noted, that under the B-Plan mass emissions are not capped, while emissions under the B-Plan are.

Provisions for New Units – Subparagraph (g)(4)(E)
PR 1109.1 has additional provisions for operators with a B-Cap for New Units. PR 1109.1 requires that the operator demonstrates that one or more of the following criteria are met before a New Unit is added to the Facility. The operator is also required to provide in writing at the time the permit application is submitted for the New Unit, which of the conditions have been met.

- The unit for which permit application is being submitted is not subject to this rule or is a Unit that will meet an exemption pursuant to paragraphs (o)(1), (o)(2), (o)(3), (o)(5), (o)(6), (o)(8), or (o)(9), if the operator met this condition the New Unit would not need to be added to the B-Cap. The New Unit must meet all of the requirements including any permit condition for limiting hours of operation or fuel usage that is specified in subdivision o for those exemptions.
- The BARCT Equivalent Mass Emissions with the New Unit is below the Facility BARCT Emission Target for the current and any future phase of the I-Plan, as calculated in Attachment B, if the operator met this condition the New Unit would not need to be added to the B-Cap. This provision is the same criteria used for a B-Plan and ensures that all Units that were not decommissioned meet the NOx Concentration Limits in Table 1 and Table 2 in aggregate, where no emissions budget from a Unit that was decommissioned can be used to establish a higher Alternative NOx Concentration Limit.
- The New Unit is not Functionally Similar to any Unit that was decommissioned in the approved B-Cap and the New Unit will not increase the overall facility throughput, if the operator met this condition the New Unit would not need to be added to the B-Cap;
- The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of the Final Phase Facility BARCT Emission Target in an approved B-Cap and the B-Cap is modified to include the New Unit and the Facility BARCT Emission Target is adjusted to incorporate the New Unit;
- The New Unit is Functionally Similar to any Unit that was decommissioned, and the B-Cap is modified with no increase of the Facility BARCT Emission Target. Any Unit that was decommissioned had an emissions budget in the B-Cap that was based on the Table 1 NOx Concentration Limit. Staff believes any New Unit that is Functionally Similar, which includes Units that are different equipment categories but provide the same purpose, should not be allowed to have an additional emissions budget in the Facility BARCT Emission Target.

The provisions for new units and unit decommissioning are to prevent a facility from shutting down units instead of installing controls on units. While shutting down a unit will result in emission reductions, the intent of PR 1109.1 is to require facilities to have BARCT levels of control on all units, or BARCT equivalent emissions in the aggregate. If a facility were to decommission a unit, take credit for the emission reductions in the B-CAP, and later install a functionally similar unit outside the B-Cap, the B-Cap would no longer be BARCT equivalent. It would not be equitable that the emissions budget from decommissioning a unit was used to allow another unit to not install pollution controls, and later install a unit that is functionally similar to the unit that was decommissioned.

SUBDIVISION (h) - I-PLAN REQUIREMENTS

An I-Plan is compliance plan that provides an alternative implementation schedule to the compliance schedule in paragraph (f)(1) which would require that all permits be submitted by January 1, 2023. An I-Plan is required for facilities that elect to comply with either a B-Plan or a B-Cap or a facility that elects to have an alternative compliance schedule for meeting Table 1 or Table 2 NOx Concentration Limits and Corresponding CO Concentration Limits.

General Requirements of an I-Plan – Paragraph (h)(1)

An owner or operator that elects to implement an I-Plan, must submit an I-Plan pursuant to paragraph (i)(1). Similar to the B-Plan and B-Cap, the I-Plan is only for Facilities with six or more Units. The I-Plan must include all of the Units included in the accompanying B-Plan if the Facility is electing to comply with a B-Plan and all of the Units included in the accompanying B-Cap if the facility is electing to comply the B-Cap. Operators do have the option to comply with the Table 1 or Table 2 limits using an alternative schedule in an I-Plan, for those operators the I-Plan must include all units at the Facility subject to the rule with the option to exclude "Optional Units" and Units that are complying with the rule under one of the exemption in under paragraphs (o)(2), (o)(5), (o)(6), (o)(8), and (o)(9). Units listed in paragraph (o)(1) shall not be included in the I-Plan as those units are subject to 1146.1 and will not be subject PR 1109.1.

The Units included in the I-Plan must be located at either a single Facility or Facilities Identify all Facilities With The Same Ownership and the owner or operator must identify the Facilities, identified by the facility identification numbers, in the I-Plan.

Selecting an I-Plan Option – Paragraph (h)(2)

The I-Plan allows refineries to implement projects within their turnaround schedules to minimize operational disruptions. Staff consulted with refineries to develop the five I-Plan options and timeframes and percent reductions. Each of the five I-Plan options have specific use criteria, such as implementation of a B-Plan, a B-Cap, or meeting Table 1 and Table 2 NOx Concentration Limits. I-Plan Option 2 and Option 3 is only available to the owner or operator of a facility that is achieving a NOx emission rate of less than 0.02 pound per million BTU of heat input for all the Boilers and Process Heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour or any Boiler or Process Heater with a rated heat input capacity of less than 40 MMBtu/hours that operates with a certified CEMS, based on the Maximum Rated Heat Input Capacity. The facility would be required to perform a one-time demonstration that their applicable boilers and process heaters meet the 0.02 pound per million BTU emission rate based on the 2021 annual emissions for those units as reported in the 2021 Annual Emissions Report.

OPTIONAL UNITS are Boilers or Process Heaters less than 40 MMBtu/hour that will meet the NOx concentration limits pursuant to subparagraph (d)(2)(B) or (d)(2)(C).

Table 6 lists the key elements of the each of the I-Plan options. The emission reductions are phased-in in either two or three. The "Percent Reduction Targets" are the percent reduction for each phase of the selected I-Plan that are applied to the total reductions required for each Facility. The "Permit Application Submittal Date" is the date that permits must be submitted to establish an Alternative BARCT NOx Limit. The "Compliance Schedule" is the timeframe the facility has to meet the Alternative BARCT NOx Limit for each Phase. By the last phase of the I-Plan, all units must have a permit condition that limits the units to the Alternative BARCT NOx limit for a facility complying with either a B-Plan or a B-Cap, or the Table 1 or Table 2 NOx concentration limits. For a B-Cap, Table 6 specifies the "B-Cap Effective Date of the Facility BARCT Emission Target" which represents the first day of the 365 days that will be used to calculate the 365-day rolling average. The compliance demonstration for the 365-day rolling average begins 365 days after the B-Cap Effective Date.

Table 3-7. PR 1109.1 Table 6 – I-Plan Percent Reduction Targets of Required Reductions and Compliance Schedule

I-Plan Option	Key Elements	Phase I	Phase II	Phase III
I-Plan Option 1 for B-Plan or Concentration Limits in Table 1 or Table 2	**Percent Reduction Targets**	**80**	**100**	**N/A**
	Permit Application Submittal Date	January 1, 2023	January 1, 2031	N/A
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		N/A
I-Plan Option 2 for B-Plan Only pursuant to subparagraph (h)(2)(E)	**Percent Reduction Targets**	**65**	**100**	**N/A**
	Permit Application Submittal Date	July 1, 2024	January 1, 2030	N/A
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		N/A
I-Plan Option 3 for B-Plan or B-Cap pursuant to subparagraph (h)(2)(E)	**Percent Reduction Targets**	**40**	**100**	**N/A**
	Permit Application Submittal Date	July 1, 2025	July 1, 2029	N/A
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		N/A
	B-Cap Effective Date of the Facility BARCT Emission Target	January 1, 2030	January 1, 2034	N/A
I-Plan Option 4 for B-Cap Only	**Percent Reduction Targets**	**50**	**80**	**100**
	Permit Application Submittal Date	N/A	January 1, 2025	January 1, 2028
	Compliance Schedule	January 1, 2024	No later than 36 months after a Permit to Construct is issued	
	B-Cap Effective Date of the Facility BARCT Emission Target	January 1, 2024	July 1, 2029	July 1, 2032
I-Plan Option 5 for B-Plan Only or Concentration Limits in Table 1 or Table 2	**Percent Reduction Targets**	**50**	**70**	**100**
	Permit Application Submittal Date	January 1, 2023	January 1, 2025	July 1, 2028
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		

The I-Plan schedule in Table 6 includes a 36-month compliance timeline to complete all of the NOx reduction projects included in each phase. Staff does not view the implementation period provided in Table 6 to be in conflict with Rule 205 that states "A permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer." This rule and its general provisions will have the approval of the Executive Officer unless the rule requires an additional Executive Officer approval (e.g., an I-Plan, B-Plan, B-Cap, etc.).

Baseline NOx Emissions and Representative NOx Concentrations – Paragraph (h)(3)

Baseline NOx Emissions and Representative NOx Concentrations are used to calculate Final Phase Facility BARCT Emission Target, the Facility BARCT Emission Targets, and BARCT Equivalent Mass Emissions for each phase of the I-Plan. During the rulemaking process staff has been working with operators to ensure that the Baseline NOx Emissions and Representative NOx Concentrations for each Facility are accurate. Since this emissions data is important to approving any I-Plan, PR 1109.1 establishes a process for final revisions, and then the data will be formalized for use for the I-Plans and implementation of B-Plans and B-Caps.

A separate document titled "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1- Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations" will be presented to the South Coast AQMD Board for approval at the adoption Public Hearing for PR 1109.1. Pursuant to paragraph (f)(3), the Baseline NOx Emissions and Representative NOx Concentrations for each facility by Unit (listed by Unit ID) approved by the South Coast AQMD shall be used, unless the owners or operators request in writing a change, the Executive Officer approves the change, and if the changes are greater than five percent, the change is presented to the Stationary Source Committee no later than February 18, 2022. After any changes are presented to the Stationary Source Committee, operators cannot change the Baseline NOx Emissions or Representative NOx Concentrations for any Unit, and must use the approved values for all emissions calculations for the I-Plan, B-Plan, and B-Cap. This approach provides greater transparency and is expected to help reduce possible delays with approving I-Plans, B-Plans, and B-Caps.

FACILITY BARCT EMISSION TARGET means the total remaining NOx emissions that are based on the Percent Reduction Targets in each phase of a Table 6 I-Plan that are applied to the overall NOx emission reductions for the Units included in an approved B-Plan or B-Cap, as calculated pursuant to Attachment B of this rule.

NOx Concentration Limits for Final Phase Facility BARCT Emission Target – Paragraph (h)(4)

Paragraph (h)(4) specifies the NOx Concentration Limits that must be used to calculate the Final Phase Facility BARCT Emission Target. Operators must use Table 1 NOx Concentration Limits for any Unit that is not listed Table 3-8. PR 1109.1 also requires that for a Unit that is designated to be decommissioned under a B-Cap, for the NOx Concentration Limit in Table 1 must be used when calculating the Final Phase Facility BARCT Emission Target.

For the conditional NOx limits, there are two pathways that an operator can take to qualify to use the Conditional Limits in Table 2 to calculate the Final Phase Facility BARCT Emissions Target for a Unit. Both pathways are designed to achieve earlier NOx reductions to be consistent with the intent of AB 617.

- ✓ The first pathway is that the operator demonstrates that the Unit will meet the conditions to use the conditional NOx Concentration Limits pursuant to paragraph (d)(3) and submits a permit application on or before June 1, 2022 for a permit condition to limit the NOx to a level not to exceed the applicable conditional NOx Concentration Limit and Corresponding CO Concentration Limits in Table 2 pursuant to subparagraph (f)(3)(A).
- ✓ The second pathway is for Units that are identified in Attachment D of PR 1109.1. Any Unit listed in Attachment D, is “pre-qualified” and operators would submit a permit application during one of the phases of the I-Plan to establish the Alternative NOx Limit, which is not limited to the levels specified in Table 2. Table D-1 applies to facilities with a B-Plan or a B-Cap and includes those Boilers and Process Heater with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour that were removed from the cost-effectiveness analysis for Table 1 due to either low emission reduction potential or high capital costs. Table D-2 applies only to facilities with a B-Cap that have selected I-Plan Option 4 and includes units that the South Coast AQMD staff has determined to meet all of the conditions in subparagraph (d)(3)(A) and Boilers and Process Heater with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour that have a representative NOx concentration level at or below 25 ppmv. Table D-2 also includes Units that met the conditions under paragraph (d)(3) for Units other than Boilers and Process Heaters greater than or equal to 40 MMBtu/hour. Units listed under Table D-2 were added since an operator that is implementing I-Plan Option 4 will achieve 50 percent of their targeted emission reductions by January 1, 2024 and will be limited to using only the Units listed in Table D-2 as Table 2 limits when establishing the Final Phase Facility BARCT Emissions Target.

Table 3-8. NOx Concentration Limits for Final Phase Facility BARCT Target

<table>
<tr><th colspan="2">NOx Concentration Limit</th><th>Unit or Specific Provision for Unit</th></tr>
<tr><td colspan="2">Table 1 NOx Concentration Limits</td><td>Any Unit not listed below and Unit that will be decommissioned under a B-Cap</td></tr>
<tr><td rowspan="3">Table 2 Conditional NOx Limit</td><td rowspan="2">An operator that does not select I-Plan Option 4</td><td>Meets the conditions in paragraph (d)(3) and permit application was submitted pursuant to subparagraph (f)(3)(A)</td></tr>
<tr><td>Is listed in Table D-1 in Attachment D of this rule, for an owner or operator submitting a B-Plan or a B-Cap</td></tr>
<tr><td>An operator submitting a B-Cap that selects I-Plan Option 4</td><td>Is listed in Table D-2 in Attachment D of this rule, for an owner or operator submitting a B-Cap that selects I-Plan Option 4</td></tr>
<tr><td colspan="2">5 ppmv</td><td>Boiler with a Rated Heat Input Capacity less than 40 MMBtu/hour</td></tr>
<tr><td colspan="2">40 ppmv</td><td>Process Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour with a representative NOx Concentration ≥ 75 ppmv provided operator achieves NOx Concentration within Phase I of an I-Plan and any additional reductions to meet the final NOx Concentration Limit are not used to meet Facility BARCT Target</td></tr>
<tr><td colspan="2">9 ppmv</td><td>Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour with a Representative NOx Concentration less than 75 ppmv</td></tr>
</table>

Operators have the option to exclude Boilers and Process Heaters less than 40 MMBtu/hour from the I-Plan, B-Plan, and B-Cap. However, if an operator includes a Boiler or Process Heater less than 40 MMBtu/hour in the I-Plan, for most situations the NOx Concentration Limit for the Final Phase BARCT Emission Target will be the final NOx Concentration limit of 5 ppmv for Boilers and 9 ppmv for Process Heaters. A provision was added for any Process Heater that is less than 40 MMBtu/hour with a high NOx concentration limit greater than 75 ppmv. Under this provision, the operator can use a NOx Concentration of 40 ppmv for the Final Phase BARCT Emission Target. Staff is aware of only one such Unit and this provision is designed to encourage the operator to reduce the NOx Concentration Limit in Phase I of the I-Plan.

Mass Emission Demonstration for an I-Plan with B-Plan or I-Plan with Table 1 or Table 2 – Paragraph (h)(5)

Paragraph (h)(5) establishes the requirements that an operator that elects to implement an I-Plan and a B-Plan, or an I-Plan to meet the NOx Limits in Table 1 and or Table 2 must demonstrate that the BARCT Equivalent Mass Emissions are less the Facility BARCT Emission Target for each phase of the I-Plan.

Mass Emission Demonstration for an I-Plan with B-Cap – Paragraph (h)(6)

Paragraph (h)(6) establishes the requirements that an operator that elects to implement an I-Plan and a B-Cap must demonstrate that the BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target for each phase of the I-Plan.

Compliance with an I-Plan without a B-Plan or B-Cap – Paragraph (h)(7)

Paragraph (h)(7) establishes the requirements that an operator that elects to implement an I Plan without a B-Plan or B-Cap shall meet the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1 or Table 2 based on the schedule in the approved I-Plan.

Compliance with an I-Plan with B-Plan – Paragraph (h)(8)

Paragraph (h)(7) establishes the requirements that an operator that elects to implement an I-Plan and a B-Plan shall meet the Alternative BARCT NOx Concentration Limits in an approved B-Plan based on the schedule in the approved I-Plan.

Requirements for Implementing an I-Plan – Paragraph (h)(9)

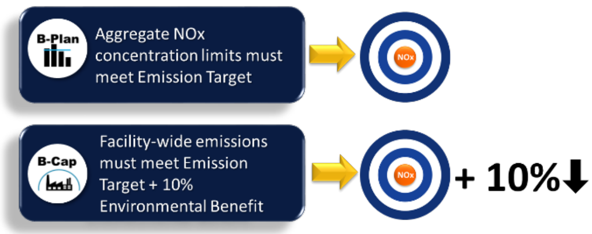
Paragraph (h)(8) establishes the requirements for operators that are implementing an I-Plan with a B-Cap which includes the following:

- Meet the Alternative BARCT NOx Concentration Limits and decommission any Units in an approved B-Cap, and implement other emission reduction strategies to achieve the Facility BARCT Emission Target for each phase, based on the schedule in the approved I-Plan;

  Demonstrate daily compliance that mass emissions from all Units in the I-Plan are below the Facility BARCT Emission Target for each phase of the I-Plan, based on a 365-day rolling average as measured pursuant to subdivisions (k) or subparagraph (n)(2)(C), based on the applicable schedule in subparagraph (h)(8)(C) or (h)(8)(D);
- Meet the Phase I and Phase II Facility BARCT Emission Targets of I-Plan Option 3 for:
  - The Baseline Facility Emissions before January 1, 2031, only if the Facility is a Former RECLAIM Facility;
  - Phase I Facility BARCT Emission Target on and after January 1, 2031 and before January 1, 2035; and
  - Phase II Facility BARCT Emission Target on and after January 1, 2035; and

- Meet the Phase I, Phase II, and Phase III Facility BARCT Emission Targets of I-Plan Option 4 for:
    - The Baseline Facility Emissions before January 1, 2025, only if the Facility is a Former RECLAIM Facility;
    - Phase I Facility BARCT Emission Target on and after January 1, 2025 and before July 1, 2030;
    - Phase II Facility BARCT Emission Target on and after July 1, 2030 and before July 1, 2033; and
    - Phase III Facility BARCT Emission Target on and after July 1, 2033.

10 Percent Environmental Benefit for the B-Cap – Subparagraph (h)(4)



The South Coast AQMD has the obligation to ensure that PR 1109.1 can be approved by CARB and U.S. EPA to be incorporated into the State Implementation Plan (SIP). Staff has discussed the provisions of the B-Cap with both agencies, and they concur that the additional 10 percent reduction in the BARCT facility emission target is appropriate for the B-Cap. Since the B-Cap establishes a mass emissions cap compliance option, the Final Phase Facility BARCT Emission Target for the B-Cap is proposed to be reduced by an additional 10 percent. Based on discussions with U.S. EPA and review of U.S. EPA's January 2001 guidance for EIPs titled "Improving Air Quality with Economic Incentive Programs" the B-Cap is an Economic Incentive Program because it is both a source-specific cap and a trading EIP and does require an environmental benefit. U.S. EPA agrees that a 10 percent reduction in NOx is the most appropriate environmental benefit approach for the B-Cap. For additional details regarding the 10 percent environmental benefit, please refer to the Response to Comments.

Two Compliance Components of the B-Cap (Subparagraphs (h)(9)(A) and (h)(9)(B))

Under the B-Cap, there are two compliance components. The first component establishes and incorporates in a permit, the Alternative BARCT NOx Limit which will be based on the averaging time for the specific equipment category in Table 1 or Table 2. The second is the demonstration that actual mass emissions from all Units under the B-Cap are below the Facility BARCT Emission Target. Under the B-Cap, the BARCT Equivalent Mass Emissions, which is the sum of the emissions for each Unit emission reduction projects, including those to meet the Alternative BARCT NOx Limit, decommissioned Units, or other reduction strategies must be implemented for each phase of the I-Plan, and the operator must demonstrate that the NOx mass emissions for all Units in the I-Plan and B-Cap will be lower than the Facility BARCT Emission Target for each phase. Operators are required to conduct a daily 365-day demonstrations that the measured NOx emissions at the facility are below the Facility BARCT Emission Target for each phase of the I-Plan. Because this requirement is based on a 365-day average, a full year of data is needed to collect the first daily average. The effective date when an operator is required to demonstrate that the annual emissions are below the Facility BARCT Emission Target is 365 days after the B-Cap Effective Compliance Date of the Facility BARCT Emission Target in Table 6, however, the first day that used in the 365-day rolling average is the B-Cap Effective Compliance Date of the Facility BARCT Emission Target. The following provides the schedule of the effective dates for the two I-Plan options for operators with a B-Cap. These dates reflect first day in which daily demonstration is required to show that based on the 365-day rolling average, NOx mass emissions from all Units in the I-Plan and B-Cap are less than the Facility BARCT Emission Target for each phase of the I-Plan. Prior to implementation of the first phase, operators will be subject to the Baseline Facility Emissions upon exiting RECLAIM. Operators will not be subject to the Facility BARCT Emission Target for Phase I, Phase II, and if applicable Phase III until the facility exits RECLAIM and becomes a former RECLAIM facility.

Table 3-9. Compliance Demonstration Dates for the Facility BARCT Emission Target for I-Plans and B-Cap

I-Plan Option	Baseline Facility Emissions	Phase I	Phase II	Phase III
I-Plan Option 3	Before January 1, 2021, only if Facility is a Former RECLAIM Facility	On and after January 1, 2031 and before January 1, 2035	On and after January 1, 2035	Not Applicable
I-Plan Option 4	January 1, 2025, only if the Facility is a Former RECLAIM Facility	On and after January 1, 2025 and before July 1, 2030	On and after July 1, 2030 and before July 1, 2033	On and after July 1, 2033

SUBDIVISION (i) – I-PLAN, B-PLAN, AND B-CAP SUBMITTAL AND APPROVAL REQUIREMENTS

I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

This subdivision specifies the submittal, and review and approval requirements for the I-Plan, B-Plan, and B-Cap. Submittal requirements for the I-Plan, B-Plan, and B-Cap are provided in paragraphs (i)(1), (i)(2), and (i)(3), respectively.

B-Plan and B-Cap Submittal – Paragraphs I-Plan Submittal Requirements – paragraph (i)(1)

This paragraph includes the submittal requirements for facilities complying with an alternative schedule in the I-Plan. On or before September 1, 2022 a facility may elect to submit an I-Plan identifying which units will be part of the plan and I-Plan option selected.

For many units, the Unit BARCT B-Cap Emissions will be lower than the BARCT Equivalent Mass Emissions for individual Units since compliance demonstration for the mass emissions cap for the B-Cap is based on a 365-day average as compared to shorter averaging times required for the Alternative NOx BARCT Emission Limits which are largely based on Table 1. PR 1109.1. This provision requires operators to provide an explanation when there is this differential. Acceptable reasons can be the averaging time, built-in compliance margin for Alternative BARCT NOx Limit, changes in capacity or use of the Unit, or any other emission reduction strategy.

B-Plan and B-Cap Submittal Requirements – paragraphs (i)(2) and (i)(3)

Submitted B-Plan and B-Cap must meet specific criteria to be considered complete:

- The device identification number and description,
- Alternative BARCT NOx limits for each unit that will cumulatively meet the Facility BARCT Emission Target

ALTERNATIVE BARCT NOx LIMIT FOR PHASE I, PHASE II, OR PHASE III is the unit specific NOx concentration limit that is selected by the owner or operator to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target in the aggregate in the B-Plan or B-Cap, where the NOx concentration limit will include the corresponding percent O_2 correction and determined based on the averaging time in Table 1 or subdivision (k), whichever is applicable.

PHASE I, PHASE III, OR PHASE III BARCT B-CAP ANNUAL EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III, decommissioned units, and other emission reduction strategies to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

PHASE I, PHASE II, OR PHASE III BARCT EQUIVALENT MASS EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates respective BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

For the purpose of B-Plan, the Alternative BARCT NOx limits is the concentration limit determined by the facility for each of the included units in the plan in a manner that the facility achieves the Facility BARCT Emission Target in aggregate. For the purpose of B-Cap, the Alternative BARCT NOx limits combined with other emission reduction strategies are used to determine the BARCT B-Cap Annual emissions.

For a B-Plan, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT Equivalent Mass Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits using the equations in Attachment B in PR 1109.1 and using the NOx Concentration Limit listed in "Baseline NOx Emissions and Representative for Facilities Regulated Under Rule 1109.1 - Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations".

For a B-Cap, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT B-Cap Annual Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits and other emission reduction strategies as shown in Attachment B in PR 1109.1. Under a B-Cap, an owner or operator must achieve Alternative NOx Limits as well as demonstrate that the actual facility-wide emissions for all units in the B-Cap are at or below the Facility BARCT Emission Target. The unit specific emission limit is based on the averaging time specified in Table 1 for the applicable unit, however, the on-going compliance demonstration of facility-wide mass emissions are based on a rolling 365-day average, each day.

PHASE I, PHASE II, OR PHASE III FACILITY BARCT EMISSION TARGET means the total NOx mass emissions per Facility that must be achieved in an approved B-Plan or B-Cap that are based the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan option in Table 6 and are calculated pursuant to Attachment B of this rule.

Also, the owner or operator is required to demonstrate compliance with the previously approved I-Plan through using the equation specified under Attachment B of PR 1109.1 to show that the percent of emission reduction from either B-Plan or B-Cap is equal or more than the I-Plan Percent Reduction Targets for each phase per PR 1109.1 Table 4.

I-Plan, B-Plan, and B-Cap Review and Approval Process – Paragraph (i)(4)

Paragraph (i)(4) provides the criteria for evaluating the I-Plan, B-Plan, and B-Cap. The Executive Officer will notify the owner or operator if the submitted plan is approved or disapproved. Approval will be based on the criteria set forth in paragraph (i)(4). The I-Plan, B-Plan, and B-Cap are subject to disapproval if any of the criteria are not met. Each of the criteria is described below.

Timely Complete Submittal of an I-Plan, B-Plan, or B-Cap – Paragraph (i)(4)(A)

The completed plans must be submitted on or before September 1, 2022 and must include all information that is required to be submitted under subparagraphs (i)(1), (i)(2) and (i)(3). The Executive Officer will review this information to ensure it meets the submittal requirements, is complete, and accurate.

Identification of Units in the I-Plan, B-Plan, or B-Cap – Subparagraph (i)(4)(B)

The plans should be limited to units that qualify for the respective plan pursuant to subparagraph (h)(1)(B) and are located at the same facility or facilities with the same ownership. Subparagraph (h)(1)(B) either directly specifies or references the Units that must be included, optional, and Units that must be excluded for the various plans. Operators have the option to submit a plan for a single

Facility or Facilities With The Same Ownership. The operator must provide the device and device identification number for each Unit for each Facility or Facility With the Same Ownership.

Selecting an I-Plan Option – Subparagraph (i)(4)(C)
The operator must provide the I-Plan option selected. Selection of any I-Plan option must meet the requirements specified in paragraph (h)(2).

Baseline NOx Emissions and Representative NOx Concentrations - (i)(4)(D)
All calculations must use the Baseline NOx Emissions and Representative NOx Concentrations that were established through the process provided under paragraph (h)(3). A B-Plan, B-Cap, or I-Plan will not be approved if an operator uses Baseline NOx Emissions or Representative NOx Concentrations for any unit that are not in the approved "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations," or that meet the conditions for using a different value as allowed under paragraph (h)(3).

BARCT Equivalent Mass Emissions and Alternative BARCT NOx Limit (i)(4)(E)
The operator must demonstrate that the BARCT Equivalent Mass Emissions were calculated pursuant to Attachment B, and the use of Alternative BARCT NOx Limits selected when calculating the BARCT Equivalent Mass Emissions meets the requirements specified under subparagraph (g)(1)(C) for the B-Plan and subparagraph (g)(2)(C) for a B-Cap. The requirements under these referenced subparagraphs have limitations on the maximum concentration limit that can be selected for an Alternative NOx Limit and references requirements for Conditional NOx Concentration Limits that also has specific requirements regarding submitting a permit application and the maximum NOx Concentration Limit that can be used for the Alternative NOx Limit. For any Unit where an Alternative NOx Limit is not specified for a given phase, the operator must use the Representative NOx Concentration, which will equate to the Baseline NOx Emissions. All of these provisions must be satisfied for approval of an I-Plan, B-Plan, and B-Cap.

Facility BARCT Emission Target – Subparagraph (i)(4)(F)
One of the key elements of the I-Plan are establishing the Facility BARCT Emission Targets. The Facility BARCT Emission Targets are based on the Percent Reduction Targets for each phase that are applied to the overall NOx reductions and must be calculated for each phase pursuant to Attachment B of PR 1109.1. The total NOx reductions are based on the Final Phase BARCT Emission Target. The operator is required to only use NOx concentration limits for each unit pursuant to paragraph (h)(4), which specifies under what situations a Unit can use the Table 1 or Table 2 conditional NOx Concentration Limit. Part of the eligibility for using a Table 2 conditional NOx Concentration Limit is that the permit application was submitted on or before June 1, 2022. If an incorrect NOx concentration limit is used to calculate the Final Phase BARCT Emission Target, the I-Plan, B-Plan, or B-Cap would be disapproved.

Demonstration that BARCT Equivalent Mass Emissions are Less than the Facility BARCT Emission Target (B-Plan) – Subparagraph (i)(4)(G)
This provision is critical for approving an I-Plan that is using a B-Plan, or an I-Plan where an operator is meeting the Table 1 or Table 2 NOx Concentration Limits. Operators must demonstrate that the BARCT Equivalent Mass Emissions are below the Facility BARCT Emission Targets for each phase when taking into account the application of Alternative NOx Concentration Limits for each phase of the I-Plan. For the B-Plan, this review ensures that the Facility BARCT Emission Target is met based on the Alternative BARCT NOx limits that the operator identified for units

under the B-Plan. The submitted B-Plan must demonstrate Equivalent Mass Emissions for units to cumulatively meet the Facility BARCT Emission Target that is adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6, using the calculation method provided in PR 1109.1 Attachment B. This demonstration is required to approve the I-Plan and B-Plan, or of the I-Plan or B-Plan is modified.

Demonstration that BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target (B-Cap) – Subparagraph (i)(4)(H)

For the B-Cap, the review ensures the BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target, where BARCT B-Cap Annual Emissions can account for emission reductions associated with implementation of Alternative BARCT NOx limits, units that the operator has identified to be decommissioned, and other reductions. The operator is required to provide an explanation when the Unit BARCT B-Cap Annual Emissions are less than the BARCT B-Cap Annual Emissions. The operator must provide sufficient details to describe the differential to ensure the differential is reasonable taking into consideration information such as the type of Unit, anticipated future usage of the Unit, and current and future capacity of Unit, use of the Unit within existing and future operations, anticipated compliance margins, increased efficiency, etc. The submitted B-Cap must be prepared using the calculation method provided in PR 1109.1 Attachment B to demonstrate that Equivalent Mass Emissions for included units cumulatively meets the Facility BARCT Emission Target less 10 percent of the overall reductions required and then adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6.

Disapproval of an I-Plan, B-Plan, and B-Cap – Paragraphs (i)(5) and (i)(6)

If Executive Officer disapproves the initial I-Plan, B-Plan or B-Cap, the proposed rule considers a 45-day period for the owner or operator to resubmit a corrected plan. Upon re-submittal, the I-Plan, B-Plan, or B-Cap will be reviewed and approved if the criteria set forth in paragraph (i)(4) is met. If the applicable criteria are not met or there are deficiencies, the I-Plan, B-Plan, or B-Cap will be disapproved. Upon second disapproval of the plan by the Executive Officer, the owner or operator must comply with the emission limits in Table 1 or Table 2 of PR 1109.1 pursuant to the compliance schedule in the selected I-Plan option. An operator who is required to meet the compliance schedule under paragraph (e)(1), is not precluded from meeting NOx and CO Concentration Limits in Table 2, provided the requirements under paragraph (d)(6) for the conditional NOx and CO Concentration Limits were met.

Modification to an Approved I-Plan, Approved B-Plan, or Approved B-Cap – Paragraph (i)(7) and (i)(8)

Paragraph (i)(7) includes the procedure the facilities must follow to apply for a modification to their approved I-Plan, B-Plan or B-Cap. In addition, PR 1109.1 includes requirements for when an I-Plan, B-Plan and B-Cap shall be modified:

- A unit identified as meeting Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (d)(2)(B);
- A unit in an approved B-Cap or B-Plan, identified as meeting Table 2 for establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is decommissioned;
- A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that unit in the currently approved I-Plan, B-Plan, or B-Cap;

- Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase;
- The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed; or
- A permit application is submitted for a New Unit that meets at least one provision of subparagraph (g)(2)(J).

Review and approval of modifications to an I-Plan, B-Plan, or B-Cap shall be based the initial review and approval process. Although there is no specified timeframe to submit a modification, the owner or operator is expected to submit a modification upon knowing one of the items under paragraph (i)(5) are triggered.

Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap – Paragraph (i)(9)
PR 1109.1 requires the Executive Officer to make the I-Plan, B-Plan, or B-Cap or modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval. Purpose of this provision is to provide an opportunity for the public to view the I-Plan, B-Plan, or B-Cap prior to approval.

SUBDIVISION (j) – TIME EXTENSION

PR 1109.1 allows two primary types of time extensions: one for specific circumstances outside of the control of the owner or operator, and the second aims to address situations where an emission reduction project falls outside of a turnaround window due to the permitting process. This subdivision establishes the criteria for time extensions, information that must be submitted, and the approval process.

Under paragraph (j)(1), an operator may request one 12-month extension for each unit for specific circumstances outside the control of the owner or operator. The operator should provide sufficient detail to explain the amount of time up to 12 months that is needed to complete the emission reduction project. If the operator requests less than 12 months, the Executive Officer will accept a subsequent request provided the total time for previous extensions plus subsequent requests does not exceed 12 months. Such a request must be made in writing no later than 90 days prior to the compliance schedule specified in the approved I-Plan. The owner or operator must demonstrate that there are specific circumstances that necessitate the additional time requested to complete the emission reduction project. The operator must provide sufficient information to document the operator took the necessary steps to ensure the project would not be delayed with a description and documentation of why the project was delayed. PR 1109.1 establishes four main areas that will be evaluated: Delays related to missed milestones; delays due to other agency approvals; delays related to delivery of parts or equipment; and delays related to workers or services. More specifically, as required under subparagraph (j)(6)(C), information or documentation as to why there was a delay of key schedules, reasons for another agency’s delay, purchase orders and invoices from vendors, as well as an explanation of the delay and additional time for contract workers and source testers.

For the second type of time extension, the amount of time allowed will be based on when the Permit to Construct was issued and the subsequent turnaround for the specific unit. An operator that requests a time extension for a turnaround under paragraph (j)(2) can also request a time extension under subparagraph (j)(1), provided the operator meets the criteria under that paragraph. The criteria for an extension for a turnaround are more specific and the operator must provide in writing at the time the permit application is submitted, the months and year(s) of the turnaround and the years for the subsequent turnaround. The Executive Officer will determine the time extension based on the current turnaround and the subsequent turnaround schedule. Other criteria are needed to ensure that in order to receive the extension, the issuance of the Permit to Construct does not align with the turnaround window because of the amount of time between the permit application submittal and issuance of the Permit to Construct. Approval of a time extension for a turnaround is based on the criteria set forth under subparagraph (j)(2)(C). Staff will assess the information and work with the operator to establish the appropriate timeframe of the extension taking into account the current turnaround and the subsequent turnaround.

Paragraph (j)(4) provides the required timeframes for a Facility to submit the written request for approval of a time extension and paragraph (j)(5) lists the specific information required such as the affected unit in which phase, the amount of extension time being requested, as well as the month and year of the turnaround if that is a reasoning for the extension.

If there is additional information needed to substantiate the request for a time extension, the Executive Officer may request additional information. This provision is to allow the operator the opportunity to provide critical information needed to approve a time request. If the Executive Officer requests additional information, the operator must provide that information based on the timeframe specified by the Executive Officer. Approval of the time extension represents an amendment to the approved I-Plan, and the operators must adhere to the timeframe established in the approved time extension to meet the NOx and CO emission limit in PR 1109.1 Table 1, PR 1109.1 Table 2, approved B-Plan, or approved B-Cap. If the Executive Officer disapproves the time extension request, the applicable emission limits must be met within 60 calendar days after notification of disapproval is received.

Facilities implementing a B-Cap (paragraph (j)(3)) may request a time extension provided a Permit to Construct was issued more than 18 months after the permit application was submitted. This provides additional time when the project was delayed due to the delay in receiving a Permit to Construct. The extension is limited to no longer than the time difference between 18 months after the complete permit applications was submitted and when the Permit to Construct was issued. Paragraph (j)(3) allows a facility with a B-Cap to request for an extension of the dates to meet the Facility BARCT Emission Target for reasons provided under paragraphs (j)(1) and (j)(2) discussed above

Paragraph (j)(4) provides the required timeframes for a Facility to submit the written request for approval of a time extension. Time extensions must be submitted no later than 180 days prior to a Compliance Date in paragraph (f)(1) or an approved I-Plan or 180 days prior to the effective date of the Facility BARCT Emission Target. This allows sufficient time for the extension to be evaluated.

Paragraph (j)(5) lists the specific information required such as the affected unit in which phase, the amount of extension time being requested, as well as the month and year of the turnaround if that is a reasoning for the extension. The time extension request shall include information needed to identify the Unit, time requested, and the reason for the extension under paragraph (j)(8). The Executive Officer will review the request based on information on key construction milestones missed, delays from agency review, delays related to the delivery of parts, or delays related to service providers for an extension related to circumstances beyond the control of the facility. For those related to a delay in receiving a Permit to Construct, dates when the application was submitted and when the Permit to Construct was issued. The length of the extension is determined based on limitations in paragraphs (j)(1) through (j)(3). An owner that receives an extension pursuant to paragraphs (j)(1) or (j)(2) shall meet the limits within the time frame in the approval. For an extension pursuant to paragraph (j)(3), the Facility BARCT Emission Target will be adjusted for each Unit where a time extension was approved.

Under paragraph (j)(10), for facilities under a B-Cap, time extensions to comply with the Facility BARCT Emission Target for individual unit projects will require an adjustment to the Facility BARCT Emission Target to ensure the facility continues to comply with B-Cap. Such an adjustment to the Facility BARCT Emission Target would be based on the reductions not yet achieved within the target due to time extension provided to that unit or units. Thus, until the unit reduces emissions as scheduled in the B-Cap, the Facility BARCT Emission Target would need to be temporarily increased. That increase would be based on the unit's emission levels from the previous phase, or if in Phase I, from the Baseline Unit Emissions. When the time extension expires, the unit should be achieving reduced emissions and the Facility BARCT Emission Target can reduced to the original levels as required by the I-Plan. The duration of the time extensions is provided in paragraph (j)(7).

SUBDIVISIONS (k) – CEMS REQUIREMENTS

This subdivision contains the CEMS requirements for the combustion equipment subject to PR 1109.1.

Units Requiring CEMS – Paragraphs (k)(1) through (k)(3)

For any unit that has a CEMS, or the owner or operator elects to use a CEMS to demonstrate compliance with the applicable PR 1109.1 NOx and Corresponding CO Concentration Limits, the installation and operation of CEMS must be in compliance with the applicable requirements of Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications when it becomes a Former RECLAIM Facility. Units with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour and Sulfuric Acid Furnaces at Former RECLAIM Facilities are required to have NOx CEMS. Additionally, Sulfuric Acid Furnaces at Former RECLAIM Facilities are required to have an oxygen CEMS within 12 months of rule adoption. Units at a Former RECLAIM Facility with a CO CEMS on the date of rule adoption must continue to operate and maintain the CO CEMS pursuant to Rules 218.2 and 218.3 to demonstrate compliance with the applicable PR 1109.1 CO limits. PR 1109.1 requires these CO CEMS be certified within 12 months of rule adoption. Until that time, facilities will continue to be subject to Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions.

Invalid CEMS Data – Paragraph (k)(4)

Invalid data shall be excluded pursuant to Rule 2012 while the facility remains in RECLAIM and then excluded pursuant to Rules 218.2 and 218.3 once the facility becomes a Former RECLAIM Facility.

Missing Data Procedures – Paragraph (k)(5)

For Facilities with an approved B-Cap with a certified CEMS that is not collecting data, the missing data calculation is based on the length of the missing data period. If the missing data period is less than 8 hours, the missing data shall be calculated using the hourly data immediately before and after the missing period. If the missing data period is more than 8 hours, the missing data shall be calculated using the maximum hourly data from the past 30 days; the 30 days begins on the day immediately before the day of the missing data occurred. It is assumed that shorter missing data periods would be similar to the most recent operational data. However, that assumption is no longer as likely during long outages and thus the worst case will be attributed to the missing data period. Missing data is only applicable to facilities utilizing a B-Cap.

SUBDIVISIONS (l) – SOURCE TEST REQUIREMENTS

This subdivision contains the source testing requirements for the combustion equipment subject to PR 1109.1.

Requirements for Source Testing – Paragraph (l)(1)

For any Unit without CEMS, compliance with the applicable PR 1109.1 NOx and Corresponding CO Concentration Limits and percent of oxygen must be demonstrated by conducting a source test according to PR 1109.1 Table 7 or Table 8. The source test subdivision has two compliance schedules, subparagraph (l)(1)(A) for Units with no ammonia in the exhaust (e.g., units without SCR) and subparagraph (l)(1)(B) for Units with ammonia in the exhaust. These paragraph also include the required averaging time for Units that are required to demonstrate compliance with PR 1109.1 concentration limits based on a source test; all Units that are not required to install and maintain CEMs must demonstrate compliance based on a source test protocol with an averaging time duration between 60 to 120 minutes.

PR 1109.1 subparagraph (l)(1)(A) requires Units that do not require CEMS and do not vent to air pollution control equipment with ammonia injection to demonstrate compliance with the PR 1109.1 NOx and CO Concentration Limits pursuant to the source test schedule in Table 7. For an owner or operator of a Unit not required to install and operate a CEMS that vents to air pollution control equipment with ammonia injection, paragraph (l)(1)(B) requires compliance with the PR 1109.1 NOx and CO Concentration Limits and the established ammonia South Coast AQMD permit limit (permit limit) to be demonstrated according to the source test schedule in Table 8. The source test schedules in Tables 7 or Table 8 vary depending on the which CEMS the Facility has for the different pollutants being measured (e.g., NOx, CO, or ammonia). When more than one pollutant requires source testing, Tables 7 and 8 require simultaneous source testing. Conducting a NOx, CO, and ammonia source test simultaneously is important as the pollutants have an inverse relationship and it is critical that all pollutants are meeting the limits.

Source Test Schedule for Units Without Ammonia Injection – PR 1109.1 Table 7

The table below has the source test schedules for Units with ammonia emissions in the exhaust. The source test schedule for these Units is divided into two categories dependent on combustion equipment: 1.) Vapor Incinerators less than 40 MMBtu/hr and Flares; and 2.) all other Units. These two categories are further divided, dependent on what type of CEMS the Unit has: A.) Units operating without NOx or CO CEMS, B.) Units operating with NOx CEMS and without CO CEMS, and C.) Units operating without NOx CEMS and with CO CEMS. Vapor incinerators typically operate intermittently and are overall low emitters so source testing every 3 years is a reasonable check on their performance. Other units, such as boilers and heaters <40 MMBTU/hr, operate more frequently so have higher emission potential thus, more source testing on an annual basis.

Source Test Schedule for Units with Ammonia Injection – PR 1109.1 Table 8

The table below has the source test schedules for Units with ammonia emissions in the exhaust. The source test schedule for these Units is divided into five categories dependent on what type of CEMS the Unit has: A.) Units operating without NOx, CO, or ammonia CEMS, B.) Units operating with NOx CEMS and without CO or ammonia CEMS, C.) Units operating with NOx and CO CEMS and without ammonia CEMS, D) Units operating with NOx and ammonia CEMS and without CO CEMS, E) Units operating with ammonia CEMS and without NOx or CO CEMS, F) Units operating with ammonia and CO CEMS and without NOx CEMS, and G) Units operating with CO CEMS and without a NOx or ammonia CEMS. Tests are initiated within 12 months after compliance with applicable NOx and CO concentration limits, and, if applicable an ammonia permit limits, and annually afterwards for those pollutants not monitored with a CEMS. If the annual tests exceed the concentration limits, then four consecutive quarterly tests are required to demonstrate compliance before resuming the annual testing schedule.

Table 3-10. PR 1109.1 Table 7 – Source Testing Schedule for Units without Ammonia Emissions in the Exhaust

CEMS Status	Source Test Schedule
Vapor Incinerators <40 MMBtu/hr and Flares	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
Units Operating without a NOx CEMS and with a CO CEMS	• Conduct a source test for NOx within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter

CEMS Status	Source Test Schedule
All Other Units	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits prior to resuming annual source tests
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter
Units Operating without NOx CEMS and with CO CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance of a NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration limit prior to resuming annual source tests

Table 3-11. PR 1109.1 Table 8 – Source Testing Schedule for Units with Ammonia Emissions in the Exhaust

CEMS Status	Source Test Schedule
Units Operating without NOx, CO, and Ammonia CEMS	• Conduct simultaneous source tests for NOx, CO, and ammonia quarterly during the first 12 months of being subject to applicable NOx concentration and CO concentration limit • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, CO concentration limit, or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit prior to resuming annual source tests
Units Operating with NOx CEMS and without CO and Ammonia CEMS	• Conduct simultaneous source tests for CO and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits, if four consecutive quarterly source tests demonstrate compliance with the CO concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance with a CO concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the CO concentration limit and ammonia permit limit prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with NOx and CO CEMS and without Ammonia CEMS	• Conduct a source test for ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the ammonia permit limit • If an annual source test demonstrates an exceedance with the ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the ammonia permit prior to resuming annual source tests
Units Operating with NOx and Ammonia CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter
Units Operating with Ammonia CEMS and without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO concentration limits prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with CO and Ammonia CEMS and without NOx CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to appliable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx concentration limit prior to resuming annual source tests
Units Operating with CO CEMS and without NOx and Ammonia CEMS	• Conduct simultaneous source tests for NOx and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration and ammonia permit limit limits prior to resuming annual source tests

Annual Source Test – Paragraph (l)(2)
The annual source test must be conducted every calendar year, but not sooner than six months from the previous source test. If the Unit has not operated for at least six consecutive calendar months, the annual source test is due no later than 90 days after the date of resumed operation and the owner or operator must demonstrate that the Unit has not been operated by using a non-resettable fuel meter to maintaining monthly fuel usage records.

CEMS In Lieu of Source Testing – Paragraph (l)(3)
This provision clarified that if an owner or operator elects to operate a CEMS in lieu of conducing source testing, the CEMS needs to meet the requirements in subdivision (k).

Initial Compliance Demonstration for New or Modified Units – Paragraph (l)(4)

The PR 1109.1 requirement for initial compliance demonstration of a new or modified unit is dependent on the averaging time of the Unit. Units with an averaging time less than 120 minutes are required to conduct an initial source test within six months from commencing operation and afterward, pursuant to the applicable schedule in PR 1109.1 Table 7 or Table 8. Units with an averaging time greater than 120 minutes as required by Table 1 or Table and Units required to adjust the NOx span range are required to demonstrate initial compliance through maintaining and operating a certified CEMS.

Submitting a Source Test Protocol and Timing of Source Test – Paragraph (l)(5)

PR 1109.1 requires the owner or operator to submit the complete source test protocol, that includes an averaging time of no less than 60 minutes but no longer than 120 minutes, to the South Coast AQMD Executive Officer for approval at least 60 days prior to conducting the source test, unless otherwise approved by the Executive Officer. The source test must be conducted within 90 days after the source test protocol has been approved by the Executive Office. A complete source test protocol should contain, but not limited to, reason for the source test, Permit to Construct or Permit to Operate, process description, sampling and analytical methods, process schematics, sampling location and related dimensions, and quality assurance procedures.

Source Test Notification – Paragraph (l)(6)

The owner or operator must notify the Executive Officer of the source test date at least one week prior to conducting the source test by calling 1-800-CUT-SMOG. The notification shall include facility name and identification number, device identification number, and the source test date.

Subsequent Source Test Protocols – Paragraph (l)(7)

Any source test conducted after the approval of the initial source test protocol does not require another approved source test, unless requested by the Executive Officer, if the method of operation of the Unit has not changed in a manner which would require a permit update, the proposed rule or permit concentration limits have not become more stringent, the referenced source test method(s) has not changed, and the approved source test protocol is representative of the Unit's operation and configuration, unless requested by the Executive Officer.

Conducting the Source Test – Paragraph (l)(8)

Upon approval of the source test protocol, the source test must be conducted using a South Coast AQMD approved contractor under the Laboratory Approval Program, during normal operating conditions and not during startup and shutdown, and using the applicable test methods:

- South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or
- South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector (GC/NDIR) – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);
- South Coast AQMD Source Test Method 207.1 – Determination of Ammonia Emissions from Stationary Sources; or
- Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

Vapor Incinerators – Paragraph (l)(9)

For Vapor Incinerators, demonstration that the Unit meets the applicable NOx Concentration Limit may be based on the NOx emission from only the burner and does not need to include the waste stream being directed to the Unit.

Source Test Reports – Paragraph (l)(10)

Source test reports shall be submitted to the Executive Officer within 90 days of the completed source test and shall include the source test results and the Unit's description.

Source Test Reports – Paragraphs (l)(11) and (l)(12)

If a source test demonstrates that a PR 1109.1 limit has been exceeded, that exceedance is considered a violation or PR 1109.1 and the owner or operator shall inform the Executive Officer within 72 hours of knowledge or when the owner or operator should have reasonably known of the exceedance.

SUBDIVISION (m) – DIAGNOSTIC EMISSION CHECKS

This subdivision contains the requirements for diagnostic emission checks which is required for any unit performing a source test every 36 months. The provisions provide the protocol to conduct the 30-minute diagnostic checks and the applicable schedule based on the corresponding source test schedule provided in this subdivision.

If emissions are measured in excess of an applicable PR 1109.1 emission limit or a permit condition using a diagnostic emissions check, this would not be considered a violation if an owner or operator corrects the problem and demonstrates compliance with the proposed rule using another diagnostic emissions check within 72 hours from the time they knew of excess emissions or shut down the unit by the end of an operating cycle.

SUBDIVISION (n) – MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

This subdivision contains the provisions for monitoring and recordkeeping for CEMS and source test records; diagnostic emission checks; startup and shutdown logs; the details of interest from either of the activity logs; and the required sequence of recordkeeping and reporting.

Facilities that utilize a B-Cap shall report daily facility-wide emissions based on CEMS data on a monthly basis. For units that do no utilize a CEMS, daily emissions shall be determined by use an enforceable method approved by the Executive Officer, such as source test results and non-resettable totalizing fuel or time meter. Additionally, daily records for units included in an approved B-Cap shall include emissions during startups, shutdowns, maintenance, and times where the CEMS data was missing or invalid. This data shall be used on a daily basis to demonstrate compliance with the B-Cap. This subdivision has a reporting provision for the owner or operator of boilers and process heaters included in a B-Plan that will meet either the Interim NOx and CO Concentration Limits in Table 4 of PR 1109.1 or the Interim NOx concentration limit of 0.03 lb/MMBtu based on a daily rolling 365-day average upon exiting RECLAIM.

Units which are exempted from compliance with NOx and CO emission limits per PR 1109.1 are required to conduct monitoring, recordkeeping and reporting and the corresponding provisions (method and schedule) are included in this subdivision.

The owner or operator of a boiler or process heater less than 40 MMBtu/hour or a unit complying with a conditional limit in PR 1109.1 Table 2 is required to maintain records of burner replacement, including number of burners and date of installation. Recordkeeping will ensure compliance with the requirement that the owner or operator of a unit complying with a conditional limit in PR 1109.1 Table 2 must meet Table 1 emission limits upon replacement of the post-combustion equipment. Subdivision (m) includes provision requiring the owner to maintain records of the dates the existing post-combustion control equipment was installed or replaced.

Vapor incinerators utilizing the exemption in paragraph (o)(9) what keep records of annual throughput and emissions.

Burner replacement, including date of replacement and number of burners, shall be recorded to confirm compliance the compliance schedule in paragraph (f)(2) that is triggered when 50 percent or more of the burners or 50 percent of the heat input is replaced.

Likewise, dates of installation or replacement of post-combustion air pollution control equipment shall be recorded to demonstrate compliance with subparagraph (f)(4)(A).

Monitoring, recordkeeping and reporting requirements for the gas turbines during Natural Gas curtailment periods are also provided under this subdivision.

Within 60 days of becoming a Former RECLAIM Facility, a list of Boilers and Process Heaters shall be submitted identifying which units will meet the Table 4 limits and which will meet Interim NOx emission rate.6

SUBDIVISION (o) – EXEMPTIONS

This subdivision includes provisions for specific combustion units which are exempted from compliance with NOx and CO emission limits under low-use, low-emitting, or operating under specific conditions. The following are the Rule 1109.1 exemptions.

Boilers and Process Heaters with rated heat input capacity of 2 MMBtu/hour or less – Paragraph (o)(1)

Small boilers and process heaters (with rated heat input capacity of less than or equal to 2 MMBtu per hour) used for comfort heating that are not used in processing units, are exempt from PR 1109.1. Small natural gas-fired water heaters, boilers, and process heaters (with rated heat input capacity of less than or equal to 2 MMBtu/hr) at PR 1109.1 facilities will be regulated under Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters regulate boilers and heaters.

Low-Use Boilers – Paragraph (o)(2)

Low-use boilers with rated heat input capacity of less than 40 MMBtu/hour that are operated at less than 200 hours per calendar year, are exempt from the emission limits in Table 1 or Table 2. Low-use units have low emissions and high cost-effectiveness to retrofit. Facilities that elect to comply with a B-Plan or B-Cap must have a permit condition limiting operating hours, include the low-use units in the approved B-Plan or B-Cap, conduct source tests pursuant to Rule 1109.1 Table 7 or Table 8, and conduct diagnostic emission checks.

Low-Use Boiler and Process Heaters – Paragraph (o)(3)

Low-use boilers and process heaters with rated heat input capacity of 40 MMBtu/hour or greater that are fired at less than 15 percent of the rated heat capacity per calendar year, are exempt from the emission limits in Table 1, Table 2, or an approved B-Plan. The exemption will be determined based on 15 percent of the fuel use as if the Unit were operated at the Maximum Rated Heat Capacity (e.g., a Unit can only burn up to 15 percent of the maximum fuel the burner could fire if it fired at 100 percent of the Maximum Rated Heat Capacity for 8760 hours per year). Such unit is required to accept a South Coast AQMD permit to operate with a condition that limits the firing rate of the unit to 15 percent of the Rated Heat Input Capacity per year. Low-use units have low emissions and high cost-effectiveness to retrofit. Low-use units will still be subject to all of the other applicable provisions in the rule, must be included in an approved B-Cap (if applicable), and subject to interim emission limits.

FCCU exemption provisions – Paragraphs (o)(4) and (o)(5)

There are several exemption provisions for FCCUs. The first provision is to address boiler inspections required under California Code of Regulations, Title 8, Section 770(b). Some FCCUs with a CO boiler have to by-pass their SCR to safely conduct the inspection and without control an exemption from the emission is needed. For those units, PR 1109.1 provides an exemption from the applicable emission limits.

There is also an exemption for process heaters used to startup the FCCU provided the process heaters is operated for 250 hours or less per calendar year. Facilities that elect to comply with a B-Plan or B-Cap must include such process heater in the approved B-Plan or B-Cap, conduct source tests pursuant to Rule 1109.1 Table 7 or Table 8, and conduct diagnostic emission checks. The unit will have to accept a permit limit with a 250 hour per year or less operating limitation.

Startup and Shutdown Boilers and Process Heaters for Sulfuric Acid Plants– Paragraph (o)(6)

Boilers used for startup and shutdown operations at a sulfuric acid plant are also low-use units that will be exempt from applicable emission limits because to control would not be cost effective. The exemption is based on the current permit limitation which limits the boilers to 90,000 MMBtu of annual heat input per calendar year or less. Startup and Shutdown Boilers that are not included in an approved B-Plan or B-Cap are also exempt from CEMS, source testing, and diagnostic emission checks.

Pilot Exemption for Boilers and Process Heaters – Paragraph (o)(7)

The emission from boilers and process heater operating only the pilot during startup or shutdown are exempt from the applicable emission limits due to low emissions and not cost effective to control.

Flare Exemptions – Paragraph (o)(8)

Non-refinery flares that emit less than or equal to 550 pounds of NOx per calendar year are exempt from the applicable emission limits provided the unit accepts a permit condition with a 550 pound of NOx per year limit. These units are not cost effective to control or replace at this time. Open flares are also exempt from the source test requirement; because there is no stack, these units cannot be source tested.

Vapor Incinerator Exemptions – Paragraph (o)(9)

Vapor incinerators with Rated Heat Input Capacity of 2 MMBtu/hour or less also have a low-emitting exemption if they emit less than 100 pounds of NOx per calendar year. These units are not cost effective to control or replace at this time. Vapor incinerators with Rated Heat Input Capacity of 2 MMBtu/hour or less that emit less than 1000 pounds but more than 100 pounds of NOx per calendar year have a low-emitting exemption until the Unit is replaced or within ten years after date of adoption, whichever happens is sooner. Both classes of vapor incinerators are required to accept a South Coast AQMD permit to operate with a condition that limits the emissions from these units to the applicable level.

PR 1109.1 ATTACHMENT A – SUPPLEMENTAL CALCULATIONS

This attachment includes calculations for the rolling average calculation for emissions data averaging and the interim NOx emission rate calculation and I-Plan Option 3 emission rate calculation for boilers and heaters greater than or equal to 40 MMBtu/hour or boilers and heaters less than 40 MMBtu/hour that operate with a certified CEMS.

PR 1109.1 ATTACHMENT B – CALCULATION METHODOLOGY FOR THE I-PLAN, B-PLAN, AND B-CAP

This attachment includes calculations for the Baseline Emissions; Base Facility BARCT Emission Target; Phase I, Phase II, and Phase III Facility BARCT Emission Target; and Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions for a B-Plan and B-Cap.

Example 3-1: Example Calculations for Refinery X

Refinery X has more than six combustion units. This example will go through the steps of how the Phase I, Phase II, and if applicable, Phase II Facility BARCT Emission Targets are established and how this sample facility will demonstrate compliance through a B-Plan or a B-Cap.

Calculating the Baseline Facility Emissions

The table below provides for each unit, the Device Identification Number (Device ID), if the units have combined stacks, the equipment category, size, Baseline Unit Emissions, and Representative NOx concentration in ppmv. The Baseline Facility Emissions are the sum of all of the Baseline Unit Emissions for each device.

Table 3-12. Calculating the Baseline Facility Total

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)
D1	D1	Heater	320	245	100
D2	D2	Boiler	210	126	38
D3	D3	SMR Heater	450	97	48
D4	D4	FCCU		83	11
D5	D5	Heater	290	54	18
D6	D6	Heater	135	29	33
D7	D7	Heater	80	24	65
D8	D8	Heater	67	14	48
D9	D9	Heater	108	12	22
D10	D10	Boiler	330	11	10
D11	D11 and D12	Heater	75	8	16
D12	D11 and D12	Heater	75	8	16
D13	D13	Heater	64	3	8
D14	D14	Thermal Oxidizer	4	3	43
D15	D15	Heater	17	3	12
D16	D16	Sulfur Recovery Unit	40	10	35
Baseline Facility Emissions			Baseline Facility Emissions	**730**	

Calculating the Final Phase Facility BARCT Emission Target

For the purpose establishing the Final Phase Facility BARCT Emission Target, the operator will select either Table 1 or Table 2. Operators can only select Table 2 for establishing the Final Phase Facility BARCT Emission Target if the unit will meet the conditions under paragraph (d)(2). Operators that are selecting Table 2 emission limits must have submitted a permit application on or before July 1, 2022 that would establish NOx limit that would be at or below the NOx limit in Table 2 for the applicable unit.

The Final Phase Facility BARCT Emission is calculated using the following equation from PR 1109.1 Attachment B:

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N	=	Number of included units in B-Plan or B-Cap
$C_{\text{Table 1 or Table 2}}$	=	The applicable NOx concentration limit for each unit i included in B-Plan or B-Cap
C_{Baseline}	=	The NOx concentration in the flue gas for unit i included in B-Plan or B-Cap as determined pursuant to section (B-2).
Baseline Unit Emissions	=	The 2017 NOx baseline emissions for unit i included in the I-Plan, or B-Plan or B-Cap as determined pursuant to section (B-1).

If a unit is qualified to meet PR 1109.1 Table 2 requirements per paragraph (d)(2) of the rule, the owner may decide to meet the applicable NOx limits in either Table 1 or Table 2 of PR 1109.1 for that unit. If the owner decides to meet PR 1109.1 Table 2 NOx limit for a unit, that limit will be included in the corresponding permit for that unit and the final remaining emissions for that unit is calculated based on the level of NOx on the permit (e.g., D11, D12, and D13 in the table below). The tables below show the process for determining how Table 1 and Table 2 NOx limits are applied. owner final selection of NOx limits for the units and the corresponding Final Phase Facility BARCT Emission.

Calculating the Emissions if Unit Meets Table 1 or Table 2 NOx Limits

In the next step, the NOx emissions are calculated assuming the unit meets Table 1 limits, and then calculated assuming the unit meets Table 2 limits. The Baseline Unit Emissions are ratioed by the Table 1 or Table 2 NOx concentration to the Representative NOx concentration.

Table 313. Calculating Emissions if Unit Meets Table 1 or Table 2 NOx Limits

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9
D2	D2	Boiler	210	126	38	5.0	16.6	7.5	24.9
D3	D3	SMR Heater	450	97	[illegible]	5.0	[illegible]	[illegible]	15.2
D4	D4	FCCU		83	[illegible]	[illegible]	[illegible]	[illegible]	60.4
D5	D5	Heater	290	54	[illegible]	[illegible]	[illegible]	[illegible]	66.0
D6	D6	Heater	135	29	33	5.0	4.4	22.0	19.3
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A
Baseline Facility Emissions				**730**					

NOx Emissions if Unit Meets 5 ppmv

NOx Emissions if Unit Meets 22

(Table 1 Limit/Representative NOx)*Baseline Unit Emissions) (5/100)*245)= 12.3 tons/year

(Table 2 Limit/Representative NOx)*Baseline Unit Emissions) (22/100)*245)= 53.9 tons/year

Pre-Screening Units for Table 2 Conditional NOx Limits

In this next step, South Coast AQMD will identify for operators those units that do not meet the conditions to use Table 2 NOx emission limits based on the potential NOx reductions. The potential NOx reductions are based on the difference between the Baseline Unit Emissions and the emissions if the unit met Table 1 (as calculated above). For the unit with a device identification number of "D1", the potential emission reductions are 232.7 tons/year (245 tons/year-12.3 tons/year). This is an initial pre-screening the operator must demonstrate that all of the conditions under paragraph (d)(2) are met before using a Table 2 NOx limit to calculate the Facility BARCT Emission Targets.

Table 314. Initial Pre-Screening for Eligibility for Table 2 Conditional Limits

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx Limit (ppmv)	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9	Not Eligible, Red > 20 TPY
D2	D2	Boiler	210	126	38	5.0	16.6	7.5	[illegible]	Not Eligible, Red > 20 TPY
D3	D3	SMR Heater	450	97	48	5.0	[illegible]	[illegible]	[illegible]	Not Eligible, Red > 20 TPY
D4	D4	FCCU		83	11	2.0	[illegible]	[illegible]	[illegible]	Eligible
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Not Eligible
D6	D6	Heater	135	29	33	5.0	4.4	22.0	19.3	Not Eligible, Red > 20 TPY
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6	Not Eligible, Red > 10 TPY
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3	Not Eligible, Red > 10 TPY
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6	Eligible
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Not Eligible
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8	Eligible
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8	Not Eligible
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A	No Table 2 Limit
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A	No Table 2 Limit
Baseline Facility Emissions				**730**						

245 tons/year - 12.3 tons/year = 232.8 tons/year
Not Eligible, 232.8 > 20 tons/year

As shown in Table 315 below, if Table 1 is selected the Facility BARCT Emission Target will be based on the emissions as if the unit met the Table 1 limits. Similarly, if Table 2 is selected, the Facility BARCT Emission Target will be based on the emissions as if the unit met Table 2 limits. If a unit is list in Table D-1 in Attachment D of PR 1109.1, the unit already meets the conditions for using Table 2 and the permit application would be submitted based on the schedule in the approved I-Plan as opposed to July 1, 2022 for units that will be meeting the provisions of subparagraphs (d)(2)(A) and (d)(2)(B). The table below notes those units as "Eligible."

The Final BARCT Emission Target is the sum of the emissions for the selected Table 1 or Table 2 NOx limits, calculated using the equation below and pursuant to section (B-2) of PR 1109.1. For this example, the Final BARCT Emission Target is 175.0 tons per year.

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N}\left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N = Number of included Units in B-Plan or B-Cap

$C_{\text{Table 1 or Table 2}}$ = The applicable NOx Concentration Limit in Table 1 or Table 2 for each Unit i included in B-Plan or B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for Unit i included in B-Plan or B-Cap

Baseline Unit Emissions = Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in the I-Plan, B-Plan or B-Cap as determined pursuant to section (B-1).

Besides three heaters (D11, D12 and D13) with Baseline Emissions below the PR 1109.1 Table 2 NOx emission limits, the owner identifies FCCU (D4), one heater (D9) and Thermal Oxidizer (D14) as potential devices to meet the requirements of PR 1109.1 Table 2 NOx limits. Therefore, the emissions of these units in the Final Phase Facility BARCT Emission Target in the final I-Plan is determined with respect to the reduction from these units to meet the applicable limits in PR 1109.1 Table 2.

Table 3-15. Calculating the Final BARCT Emission Target

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx Limit (ppmv)	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)	Units Possibly Eligible for ... Conditions)	Operator Selects Table 1 or Table 2 Limits (Table 2 Must Meet (d)(2))	NOx Lmit Based Selected Table 1 or Table 2 Limits (ppmv)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9	Not Eligible, Red > 20 TPY	Table 1	12.3
D2	D2	Boiler	210	126	38	5.0	16.6	7.5	24.9	Not Eligible, Red > 20 TPY	Table 1	16.6
D3	D3	SMR Heater	450	97	48	5.0	10.1	7.5	15.2	Not Eligible, Red > 20 TPY	Table 1	10.1
D4	D4	FCCU		83	11	2.0	15.1	8.0	60.4	Eligible	Table 2	60.4
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Not Eligible	Table 1	15.0
D6	D6	Heater	135	29	33	5.0	4.4	22.0	19.3	Not Eligible, Red > 20 TPY	Table 1	4.4
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6	Not Eligible, Red > 10 TPY	[illegible]	1.8
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3	Not Eligible, Red > 10 TPY	[illegible]	1.5
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6	Eligible	[illegible]	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Not Eligible	Table 1	5.5
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8	Eligible	Table 2	6.8
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8	Not Eligible	Table 1	2.1
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A	No Table 2 Limit	Table 1	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A	No Table 2 Limit	Table 1	8.6
Baseline Facility Emissions				**730**							Final Phase Facility BARCT Target	**175.0**

Initial Screening Based on Unit Reductions Only - Must Verify Other Conditions Met

NOx emissions based on Table selection
Cannot select Table 2, if

Calculating the Total Facility NOx Emission Reductions for B-Plan

The Total Facility NOx Emission Reductions are the difference between the Baseline Facility Emissions and the Final Phase Facility BARCT Emission Target.

Total Facility NOx Emission Reductions must be calculated using the following equation, pursuant to section (B-3.1) of PR 1109.1:

$$\text{Total Facility NOx Emission Reductions} \\ = \text{Baseline Facility Emissions} - \text{Final Phase Facility BARCT Emission Target}$$

Based on the calculated Baseline Emissions (section B-1) and Final Phase Facility BARCT Emission (section B-2) for this example, the Facility Total NOx Emission Reductions is equal to 555.0 tons/year (730 tons/year – 175.0 tons/year).

Table 3-16. Facility Total NOx Emission Reductions

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx Limit (ppmv)	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)	Operator Selects Table 1 or Table 2 Limits (Table 2 Must Meet (d)(2))	NOx Lmit Based Selected Table 1 or Table 2 Limits (ppmv)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9	Not Eligible, Red > 20 TPY	Table 1	12.3
D2	D2	Boiler	210	126	38	5.0	16.6	7.5	24.9	Not Eligible, Red > 20 TPY	Table 1	16.6
D3	D3	SMR Heater	450	97	48	5.0	10.1	7.5	15.2	Not Eligible, Red > 20 TPY	Table 1	10.1
D4	D4	FCCU		83	11	2.0	15.1	8.0	60.4	Eligible	Table 2	60.4
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Not Eligible	Table 1	15.0
D6	D6	Heater	135	29	33	5.0	4.4	22.0	19.3	Not Eligible, Red > 20 TPY	Table 1	4.4
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6	Not Eligible, Red > 10 TPY	Table 1	1.8
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3	Not Eligible, Red > 10 TPY	Table 1	1.5
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6	Eligible	Table 2	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Not Eligible	Table 1	5.5
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8	Eligible	Table 2	6.8
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8	Not Eligible	Table 1	2.1
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A	No Table 2 Limit	Table 1	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A	No Table 2 Limit	Table 1	8.6
Baseline Facility Emissions				730								175.0

Total Facility NOx Emission Reductions
730 tons/year - 175 tons/year = 555 tons/year

B-Plan

Calculating Phase I, Phase II, and Phase III Facility BARCT Emission Targets for an I-Plan with a B-Plan

The owner with a B-Plan calculates the expected level of NOx emissions at each phase of the selected I-Plan option using the following equations, pursuant to section (B-4) of PR 1109.1:

$$\text{Phase I Facility BARCT Emission Target}_{\text{B-Plan}} \\ = \text{Baseline Emissions} \\ - (\text{Each Phase Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})$$

For the final phase, the Phase Facility BARCT is the Final Phase Facility BARCT Target.

Here, if the owner chooses to proceed with an I-Plan Option 1, the calculations will be as follows:

$$\textbf{Phase I Facility BARCT Emission Target}_{\textbf{B-Plan}} = \mathbf{730 - (555 \times 0.7) = \ 341.5\ tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Plan}} = \\ \textbf{Final Phase Facility BARCT Emission Target} = \mathbf{175.0\ tons/year}$$

Calculating Phase I, Phase II, and if Applicable Phase III BARCT Equivalent Mass Emissions for a B-Plan

After the Phase I and II Facility BARCT Emission Targets are established, the operator then calculates the BARCT Equivalent Mass Emissions. For the B-Plan, the emissions are based on the concentration limits. Units that are decommissioned must be removed from the Baseline Facility Emissions and the Facility BARCT Emission Targets. As shown in the table below, the operator selects the Phase I Alternative BARCT Emission Limit for each unit. For the B-Plan, the Phase I

BARCT Equivalent Mass Emissions are the sum of the emissions for all units using the Alternative BARCT Emission Limits. In the example below, the Phase I BARCT Equivalent Emissions are 288.9 tons/year and the Phase II BARCT Equivalent Emissions are 173.8 tons/year.

Table 3-17. Calculating Phase I BARCT Equivalent Mass Emissions for B-Plan

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)
D1	D1	Heater	320	245	100	Not Eligible, Red > 20 TPY	N/A	15.0	36.8	5.0	12.3
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20	[illegible]	15.0	49.7	5.0	16.6
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20	[illegible]	10.0	20.2	10.0	20.2
D4	D4	FCCU		83	11	Eligible	[illegible]	7.0	52.8	7.0	52.8
D5	D5	Heater	290	54	18	Not Eligible	[illegible]	6.0	18.0	6.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	N/A	33.0	29.0	[illegible]	[illegible]
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	N/A	65.0	24.0	[illegible]	[illegible]
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	N/A	9.0	2.6	[illegible]	[illegible]
D9	D9	Heater	108	12	22	Eligible	N/A	18.0	9.6	[illegible]	[illegible]
D10	D10	Boiler	330	11	10	Not Eligible	N/A	10.0	11.0	[illegible]	[illegible]
D11	D11 and D12	Heater	75	8	16	Eligible	N/A	12.0	6.0	[illegible]	[illegible]
D12	D11 and D12	Heater	75	8	16	Eligible	N/A	20.0	10.0	[illegible]	[illegible]
D13	D13	Heater	64	3	8	Eligible	N/A	8.0	3.0	[illegible]	[illegible]
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	N/A	43.0	3.0	10.0	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	N/A	12.0	3.1	9.0	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	N/A	35.0	10.0	14.0	4.0
Baseline Facility Emissions				**730**			Phase I BARCT Equivalent Emissions		**288.9**		**173.8**

Operator selects Alternative BARCT Emission Limit for Each Unit

Phase I BARCT Equivalent Emissions are the sum of the mass emission for each unit using the Alternative BARCT

For the B-Plan, the operator must calculate the BARCT Equivalent Mass Emissions for each phase of the I-Plan, using the equation in sections (B-6.1) and (B-6.2) of PR 1109.1. The Phase I and Phase II (if not the final phase) BARCT Equivalent Mass Emissions for the B-Plan equation is shown below. Final Phase BARCT Equivalent Mass Emissions (i.e., Phase II if it is the final phase and Phase III) are calculated with the same equation but using only the Alternative BARCT Emission Limits for the applicable phase (using Representative NOx Concentrations for Phase III is not allowed).

$$\text{Phase I and Phase II BARCT Equivalent Mass Emissions}_{\text{B-Plan}} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}} \ \boldsymbol{OR} \ C_{\text{Baseline}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N = Number of included units in B-Plan under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit for Phase I in an approved B-Plan for unit i included in the B-Plan

C_{Baseline} = The NOx concentration in the flue gas for unit i included in the B-Plan

Baseline Unit Emissions = The 2017 NOx baseline emissions for unit i included in the B-Plan.

Demonstration that BARCT Equivalent Mass Emissions is Less than or Equal to Facility BARCT Emission Target for the B-Plan

For the B-Plan, the last step is to demonstrate for each phase that the BARCT Equivalent Mass Emissions are less than or equal to that Phase Facility BARCT Emission Target. As shown in the table below, the Phase I BARCT Equivalent Emissions are 288.9 tons/year which are less than the

Phase I Facility BARCT Emission Target of 341.5 tons/year; and the Phase II BARCT Equivalent Mass Emissions are 173.8 tons/year which are less than the Phase II Facility BARCT Emission Target of 175.0 tons/year. If the BARCT Equivalent Mass Emissions are greater than the Facility BARCT Emission Target, then the operator will need to lower the Alternative BARCT Emission Limits for all or part of the included units in the corresponding phase. For the B-Plan, the Facility BARCT Emission Targets are used only to demonstrate that the Alternative BARCT emission limits are in aggregate at or below the Facility BARCT Emission Target. Operators using an approved B-Plan are not required to adhere to a facility-wide emission cap but must implement the Alternative BARCT Emission Limits for each phase.

Table 3-18. Demonstrating the B-Plan Will Achieve the Facility BARCT Emission Targets

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)
D1	D1	Heater	320	245	100	Not Eligible, Red > 20 TPY	N/A	15.0	36.8	5.0	12.3
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	N/A	15.0	49.7	5.0	16.6
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	N/A	10.0	20.2	10.0	20.2
D4	D4	FCCU		83	11	Eligible	N/A	7.0	52.8	7.0	52.8
D5	D5	Heater	290	54	18	Not Eligible	N/A	6.0	18.0	6.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	N/A	33.0	29.0	4.0	3.5
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	N/A	65.0	24.0	9.0	3.3
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	N/A	9.0	2.6	9.0	2.6
D9	D9	Heater	108	12	22	Eligible	N/A	18.0	9.6	18.0	9.6
D10	D10	Boiler	330	11	10	Not Eligible	N/A	10.0	11.0	8.0	8.8
D11	D11 and D12	Heater	75	8	16	Eligible	N/A	12.0	6.0	12.0	6.0
D12	D11 and D12	Heater	75	8	16	Eligible	N/A	20.0	10.0	[illegible]	10.0
D13	D13	Heater	64	3	8	Eligible	N/A	8.0	3.0	[illegible]	3.0
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	N/A	43.0	3.0	[illegible]	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	N/A	12.0	3.1	[illegible]	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	N/A	35.0	10.0	[illegible]	4.0
Baseline Facility Emissions				**730**			Phase I BARCT Equivalent Emissions		**288.9**	Phase II BARCT Equivalent	**173.8**
							Facility BARCT Emission Targets		**341.5**		**175.0**

B-Cap

Calculating the Total Facility NOx Emission Reductions for B-Cap

Table 3-19. Calculating Phase I BARCT Equivalent Mass Emissions for B-Cap

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all [illegible]	Operator Selects Table 1 or Table 2 Limits (Table 2 Must Meet (d)(2))	NOx Lmit Based Selected Table 1 or Table 2 Limits (ppmv)	Emissions Based on Selected Table 1 or Table 2 Limits (Tons/Year)
D1	D1	Heater	320	245	100	[illegible]	Table 1	5.0	**12.3**
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	Table 1	5.0	16.6
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	Table [illegible]	[illegible]	10.1
D4	D4	FCCU		83	11	Eligible	Table [illegible]	[illegible]	60.4
D5	D5	Heater	290	54	18	Not Eligible	Table [illegible]	[illegible]	15.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	Table 1	5.0	4.4
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	Table 1	5.0	1.8
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	Table 1	5.0	1.5
D9	D9	Heater	108	12	22	Eligible	Table 2	18.0	9.8
D10	D10	Boiler	330	11	10	Not Eligible	Table 1	5.0	5.5
D11	D11 and D12	Heater	75	8	16	Eligible	Table 2	18.0	9.0
D12	D11 and D12	Heater	75	8	16	Eligible	Table 2	18.0	9.0
D13	D13	Heater	64	3	8	Eligible	Table 2	18.0	6.8
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	Table 1	30.0	2.1
D15	D15	Heater	17	3	12	No Table 2 Limit	Table 1	9.0	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	Table 1	30.0	8.6
Baseline Facility Emissions				**730**					**175.0**

Unit will be decommissioned

12.3 was added to the Target

The calculation approach for Total Facility NOx Emission Reductions in B-Cap is the same as the calculation approach for a B-Plan, but with an additional 10 percent. This is a 10 percent environmental benefit to meet U.S. EPA requirements for Economic Incentive Programs. Under this example for B-Cap, I-Plan Option 4 is used. If a unit is listed in Table D-2 in Attachment D of PR 1109.1, the unit already meets the conditions for using Table 2 and the permit application would be submitted based on the schedule in the approved I-Plan as opposed to June 1, 2022 for units that will be meeting the provisions of paragraphs (d)(3) and (f)(3). Under I-Plan Option 4, only units that are identified in Table D-2 are allowed to meet the Table 2 conditional limits in lieu of Table 1. These units meet all the conditions under subparagraph (d)(3) and have a representative NOx concentration at or below 25 ppmv.

Total Facility NOx Emission Reductions for B-Cap must be calculated using the following equation pursuant to section (B-3.2) of PR 1109.1:

$$\begin{aligned}\text{Total Facility NOx Emission Reductions}_{\text{B-Cap}} &= \text{Baseline Facility Emissions} \\ &- (\text{Final Phase Facility BARCT Emission Target} \times 0.9)\end{aligned}$$

Based on the calculated Baseline Emissions (section B-1) and Final Phase Facility BARCT Emission (section B-2) for this example, the Facility Total NOx Emission Reductions is equal to 572.6 tons/year (730 tons/year – 175.0 tons/year × 0.9).

Calculating Phase I, Phase II, and Phase III BARCT Facility Emission Targets for an I-Plan with a B-Cap

The calculation for the Phase I, Phase II, and Phase III BARCT Facility Emission Targets is the same as the calculation approach for a B-Plan, except that the Facility BARCT Emission Target for each phase of I-Plan will be adjusted for any unit with an approved time extension. This adjustment is applied by adding the Baseline Unit Emissions in Phase I and the Unit BARCT B-Cap Annual Emissions from the previous phase in Phase II and Phase III for each Unit with an approved time extension to the corresponding phase Facility BARCT Emission Target based on the equation in sections (B4.4.1), (B-4.4.2) and (B-4.4.3) of PR 1109.1.

For I-Plan Option 4, the Phase I, Phase II and Phase III Facility BARCT Emission Target calculations will be as follows, using the equations in sections (B4.4.1), (B-4.4.2) and (B-4.4.3):

$$\textbf{Phase I Facility BARCT Emission Target}_{\textbf{B-Cap}} = \mathbf{730 - (572.6 \times 0.5) = 443.7} \textbf{ tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Cap}} = \mathbf{730 - (572.6 \times 0.8) = 272.03} \textbf{ tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Cap}} = \mathbf{730 - (572.6 \times 1.0) = 157.5} \textbf{ tons/year}$$

Calculating Phase I, Phase II, and if Applicable Phase III BARCT Equivalent Mass Emissions for a B-Cap

After the Facility BARCT Emission Targets for each phase are established, the operator then calculates the BARCT Equivalent Mass Emissions for each phase using the corresponding equations in sections (B-6.3) and (B-6.4) of PR 1109.1. As shown in the table below, the operator selects the Alternative BARCT Emission Limit or Representative NOx Concentrations for each unit and any decommissioned units in each phase. The BARCT Facility Emission Target must be based on Table 1 NOx limits for any decommissioned unit. The BARCT Equivalent Mass Emissions are based on the concentration limits and emission reductions from decommissioned units.

Table 3-20. Calculating Phase I BARCT Equivalent Mass Emissions for B-Cap

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all [illegible]	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase I BARCT B-Cap Annual Emissions (Tons/year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)	Phase II BARCT B-Cap Annual Emissions (Tons/year)	Phase III Alternative BARCT Emission Limit (ppmv)	Phase III BARCT Equivalent Emissions (Tons/Year)	Phase III BARCT B-Cap Annual Emissions (Tons/year)
D1	D1	Heater	320	245	100	N [illegible] Unit will be decommissioned	Yes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	No	38.0	126.0	126.0	38.0	126.0	70.0	10.0	33.2	33.2
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	No	45.0	90.9	85.0	10.0	20.2	20.2	10.0	20.2	20.2
D4	D4	FCCU		83	11	Eligible	No	11.0	83.0	83.0	7.0	52.8	52.8	7.0	52.8	30.0
D5	D5	Heater	290	54	18	Not Eligible	No	18.0	54.0	50.0	6.0	18.0	18.0	6.0	18.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	No	6.0	5.3	5.3	6.0	5.3	5.3	6.0	5.3	5.3
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	No	65.0	24.0	24.0	65.0	24.0	24.0	4.0	1.5	1.5
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	No	48.0	14.0	14.0	48.0	14.0	14.0	4.0	1.2	1.2
D9	D9	Heater	108	12	22	Eligible	No	22.0	12.0	12.0	18.0	9.8	9.8	18.0	9.8	9.8
D10	D10	Boiler	330	11	10	Not Eligible	No	10.0	11.0	11.0	10.0	11.0	11.0	8.0	8.8	8.8
D11	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	12.0	6.0	6.0	12.0	6.0	6.0
D12	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	20.0	10.0	10.0	20.0	10.0	10.0
D13	D13	Heater	64	3	8	Eligible	No	8.0	3.0	3.0	8.0	3.0	3.0	8.0	3.0	3.0
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	No	43.0	3.0	3.0	43.0	3.0	3.0	10.0	0.7	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	No	12.0	3.0	3.0	12.0	3.0	3.0	9.0	2.3	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	No	14.0	4.0	4.0	35.0	10.0	10.0	14.0	4.0	4.0
Baseline Facility Emissions				730					449.2	439.3		316.1	260.1		176.7	153.8

Calculating Phase I, Phase II, and if Applicable Phase III BARCT B-Cap Annual Emissions

The owner or operator then must calculate the BARCT B-Cap Annual Emissions for each phase of the I-Plan, pursuant to equations in section (B-7) of PR 1109.1. For the B-Cap, the BARCT B-Cap Annual Emissions for each phase are the sum of the emissions for all units using the Alternative BARCT Emission Limits, accounting for any decommissioned units, and throughput or other emission reductions. In the example below, the Phase I BARCT Equivalent Emissions are 439.3 tons/year, the Phase II BARCT Equivalent Emissions are 260.1 tons/year and the Phase III BARCT Equivalent Emissions are 153.8 tons/year.

In the table above, green cells identify the units that contribute to the emissions reductions in each phase through implementation of emission reduction projects. Yellow cells are the units with emission reduction achieved only through replacing units, reducing throughput or other reductions. The orange cells specify the corresponding Unit BARCT B-Cap Annual Emissions for retrofitted or not retrofitted units based on reduction strategies which are different from the mass emission for that unit based on the Alternative NOx Concentration Limit. The operator is required by the rule to provide an explanation to the Executive Officer about these units for which the Unit BARCT B-Cap Annual Emissions are less than the BARCT Equivalent Mass Emissions.

The Phase I and Phase II (if not the final phase) BARCT B-Cap Annual Emissions for the B-Cap equation is shown below. Final Phase BARCT B-Cap Annual Emissions (i.e., Phase II if it is the final phase and Phase III) are calculated with the same equation, using only the Alternative BARCT Emission Limits for the applicable phase (using Representative NOx Concentrations for Phase III is not allowed) and additional emission reduction strategies to reduce mass emissions.

Phase I and Phase II BARCT B-Cap Annual Emissions

$$= \sum_{i=1}^{N} \left[\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}} \; \boldsymbol{OR} \; C_{\text{Baseline}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})_i \right]$$

Where:

N = Number of included units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit for Phase I in an approved B-Plan for unit i included in the B-Cap

C_{Baseline} = The NOx concentration in the flue gas for unit i included in the B-Cap

Baseline Unit Emissions = The 2017 NOx baseline emissions for unit i included in the B-Plan

Throughput or Other Reductions = Emission reductions other than reduc4ing the concentration limit.

In this example (Figure 3-20), unit D1 is decommissioned and the difference between the sum of units BARCT Equivalent Emissions and units BARCT B-Cap Annual Emissions in each phase is due to emission reductions from "throughput or any other emission reductions" applied to unit D5 in Phase I, D2 in Phase II and unit D4 in Phase III (highlighted in orange color).

Demonstration that BARCT B-Cap Annual Emissions is Less than or Equal to Facility BARCT Emission Target for the I-Plan and On-Going Demonstration

For the B-Cap, there are two demonstrations that are required. The first demonstration is that the Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions are less than or equal to the respective Phase I, Phase II, and Phase III Facility BARCT Emission Target. The operator is required to take permit conditions for each of the Alternative BARCT Limits in the approved B-Cap. Under the B-Cap, the second compliance demonstration is to continuously demonstrate that facility-wide emissions are below the Facility BARCT Emission Target for each phase. Staff believes that this two-pronged compliance demonstration is needed to ensure that there is a commitment to implement the Alternative BARCT Emission Limits while ensuring mass emissions are continuously below the Phase I, II, and III Facility BARCT Emission Targets.

As shown in the table below, the Phase I BARCT Equivalent Emissions are 439.3 tons/year which are less than the Phase I Facility BARCT Emission Target of 443.7 tons/year; the Phase II BARCT Equivalent Mass Emissions are 260.1 tons/year which are less than the Phase II Facility BARCT Emission Target of 272.0 tons/year; and the Phase III BARCT B-Cap Annual Emissions are 153.8 tons/year which are less than the Phase III Facility BARCT Emission Target of 157.5 tons/year. The operator must demonstrate on an ongoing basis that actual emission for all units in the B-Cap are below the Phase Facility BARCT Emission Targets.

Table 3-21. Demonstrating the B-Cap Will Achieve the Facility BARCT Emission Targets

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase I BARCT B-Cap Annual Emissions (Tons/year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)	Phase II BARCT B-Cap Annual Emissions (Tons/year)	Phase III Alternative BARCT Emission Limit (ppmv)	Phase III BARCT Equivalent Emissions (Tons/Year)	Phase III BARCT B-Cap Annual Emissions (Tons/year)
D1	D1	Heater	320	245	100	N[illegible]	Yes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	No	38.0	126.0	126.0	38.0	126.0	70.0	10.0	33.2	33.2
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	No	45.0	90.9	85.0	10.0	20.2	20.2	10.0	20.2	20.2
D4	D4	FCCU		83	11	Eligib[illegible]	[illegible]	[illegible]	83.0	83.0	7.0	52.8	52.8	7.0	52.8	30.0
D5	D5	Heater	290	54	18	Not Elig[illegible]	[illegible]	18.0	54.0	50.0	6.0	18.0	18.0	6.0	18.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Re[illegible]	[illegible]	6.0	5.3	5.3	6.0	5.3	5.3	[illegible]	[illegible]	5.3
D7	D7	Heater	80	24	65	Not Eligible, Re[illegible]	[illegible]	65.0	24.0	24.0	65.0	24.0	24.0	4.0	[illegible]	1.5
D8	D8	Heater	67	14	48	Not Eligible, Re[illegible]	[illegible]	48.0	14.0	14.0	48.0	14.0	14.0	4.0	[illegible]	1.2
D9	D9	Heater	108	12	22	Eligib[illegible]	[illegible]	22.0	12.0	12.0	18.0	9.8	9.8	18.0	[illegible]	9.8
D10	D10	Boiler	330	11	10	Not Eligible	No	10.0	11.0	11.0	10.0	11.0	11.0	8.0	8.8	8.8
D11	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	12.0	6.0	6.0	12.0	6.0	6.0
D12	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	20.0	10.0	10.0	20.0	10.0	10.0
D13	D13	Heater	64	3	8	Eligible	No	8.0	3.0	3.0	8.0	3.0	3.0	8.0	3.0	3.0
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	No	43.0	3.0	3.0	43.0	3.0	3.0	10.0	0.7	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	No	12.0	3.0	3.0	12.0	3.0	3.0	9.0	2.3	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	No	14.0	4.0	4.0	35.0	10.0	10.0	14.0	4.0	4.0
Baseline Facility Emissions				**730**					**449.2**	**439.3**		**316.1**	**260.1**		**176.7**	**153.8**
								Facility BARCT Emission Targets		**443.7**			**272.0**			**157.5**

Unit will be decommissioned

Permit to Construct was issued **3 months** after 18 months from the date the complete permit application submittal

Executive Officer approved a **12-month** time extenion for this Unit

On-Going Demonstration that Actual Emissions ≤ Facility BARCT Emission Target

Revised @ 54 months from permit application submittal	**455.7**	Late permit for D3 in Phase I
Revised @ 54+3 months from permit application submittal	**443.7**	Permit issued for D3/Construction is done
Revised @ 54 months from permit application submittal	**304.0**	Time extension approved for D5 in Phase II
Revised @ 54+12 months from permit application submittal	**272.0**	Permit issued for D5/Construction is done

Pursuant to paragraph (j)(10) of PR 1109.1, if an owner or operator receives an approval for a time extension, the Facility BARCT Emission Target will be adjusted for the corresponding phase of selected I-Plan. In this example, Permit to Construct was not issued within 18 months since the complete permit application submittal for units D3 and time extension was approved for Unit D5 (highlighted in pink color). Therefore, the Facility BARCT Emission Target is adjusted for the corresponding phase of I-Plan. Here, the owner or operator submitted the permit application for Unit D3, but the Permit to Construct was issued for this unit with 3 months delay. Therefore, the Facility BARCT Emission Target for Phase I is adjusted by the "Baseline Unit Emission" value of 97 tpy (highlighted in light blue color), using the equation for Phase I Facility BARCT Emission Target for B-Cap (refer to PR 1109.1 Section (B-4.4.1)). The Phase I Facility BARCT Emission Target is adjusted again after 3 months by reducing the "Baseline Unit Emission" value for D3. In Phase II, Unit D5 was approved by the Executive Officer for a 12-month time extension and the Facility BARCT Emission Target for Phase II is adjusted by the Unit BARCT B-Cap Annual Emissions for Unit D5 in the previous phase (50 tpy in Phase I) using the equation for Phase II Facility BARCT Emission Target for B-Cap (refer to PR 1109.1 Section (B-4.4.2)). The Phase II Facility BARCT Emission Target is adjusted again after 12 months by reducing the "Unit BARCT B-Cap Annual Emissions in Phase I" for D5.

PR 1109.1 ATTACHMENT C – FACILITIES EMISSIONS – BASELINE AND TARGETS

Attachment C contains Baseline Facility Emissions as reported by the facilities with six or more units in their 2017 Annual Emissions Reports, or another year, as approved by the Executive Officer. PR 1109.1 Table C-1, presented in the table below, provides the Baseline Facility Emissions for the corresponding facilities subject to PR 1109.1.

Table 3-22. PR 1109.1 Table C-1 – Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017 or Representative Year) (tons/year)
AltAir Paramount, LLC	187165	28
Chevron Products Co.	800030	701
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	386
Phillips 66 Co/LA Refinery Wilmington PL	171107	462
Tesoro Refining and Marketing Co., LLC – Carson	174655	613
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	594
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	35
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	898
Ultramar Inc.	800026	248
Valero Wilmington Asphalt Plant	800393	5

PR 1109.1 ATTACHMENT D – UNITS QUALIFY FOR CONDITIONAL LIMITS IN B-PLAN AND B-CAP

Table 3-23. PR 1109.1 Table D-1 – Process Heaters and Boilers >40 MMBtu/hr That Qualify for Conditional Limits in B-Plan or B-Cap

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
174655	D1465	427
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D384	48
800436	D385	24
800436	D388	147
800436	D770	63
800436	D777	146

Table 3-24. PR 1109.1 Table D-2 – Units That Qualify for Conditional Limits in B-Plan or B-Cap

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	C2979	4
174655	D1465	427
174655	D250	89
174655	D33	100
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
174655	D63	360
181667	C686	4
181667	C687	4
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D1669	342
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800030	D203	-
800436	D1122	140
800436	D158	204
800436	D214	56
800436	D215	36
800436	D216	31

Facility ID	Device ID	Size (MMBtu/hr)
800436	D217	31
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

CHAPTER 4 IMPACT ASSESSMENT

INTRODUCTION

There are 16 facilities with a total of 284 units that will be subject to the PR 1109.1 which are all currently regulated under the RECLAIM program. PR 1109.1 will achieve emission reductions for every class and category of refinery equipment.

RULE DEVELOPMENT SUPPORTING MATERIALS AND SOURCES

Rule Development and Data Surveys

Staff conducted several surveys to develop a comprehensive understanding of the equipment at petroleum refineries and related industries, and their operational record. The following data surveys were requested and collected from each of the sixteen facilities impacted by PR 1109.1:

- Facility Based Equipment Data Survey
- Control Equipment Project Costs Data Survey
- CEMS Data Survey
- Fuel Gas Sulfur Content Data Survey
- Revised Control Equipment Project Cost Data Survey

Facility Based Equipment Data Survey

After holding several working group meetings to establish the universe of facilities and equipment that would be subject to PR 1109.1, staff developed a survey questionnaire to gather pertinent detailed information for the rule development. The intent of the data survey was to assist South Coast AQMD staff in developing PR 1109.1 and conducting the BARCT assessment to establish the NOx and CO limits. The survey was sent to all 16 facilities on May 24, 2018. The survey requested detailed information and data for all NOx sources affected by the proposed rule at each facility. The survey development was a collaborative process with the stakeholders and took several months to agree to the specific information being requested. Due to the level of detailed data requested, the facilities were provided approximately six months to submit the data. The facilities reported nearly 125 data points for each piece of equipment, including five years of annual fuel data, five years of annual emissions data, current and planned NOx controls, installation costs for planned controls, number of burners per unit, age of equipment, etc. In total, some facilities reported almost 3,000 data points and staff evaluated over 40,000 data points.

Control Equipment Project Costs Data Survey

The second survey was distributed to stakeholders prior to conducting site visits. As part of the rule development, staff conducted at least one site visit to each of the affected facilities from April through August 2019. This survey focused on the potential control technology, total installation cost, and operating and maintenance (O&M) costs. Staff requested a detailed cost breakdown for each project, but the level of detail varied depending on the stage of the project, such as the design and engineering phase, permitting, or already completed. Data from projects in early development stage was less detailed and more preliminary than projects in later stages of development.

In March 2021, four facilities provided updated revised cost data for potential control projects for 108 units in total, including new SCRs and SCR upgrades, low NOx burners, wet gas scrubbers, and unit replacement. Staff used the first cost survey data for facilities that did not provide updated costs in the second submission. While the facility's focus in providing updated cost was on boilers and process heaters greater than or equal to 40 MMBtu/hr, which included 91 data points, some facilities provided updated costs for other categories including FCCU, Gas Turbine, SMR Heater, SRU/TG Incinerator, and Vapor Incinerator with a total of 17 data points as it is shown in the table below.

Table 4-1. Number of Units with Facility Provided Cost Data by Equipment Category and Facility

	Heaters	Boilers	SMR Heaters	FCCU	Gas Turbine	SRU/TG Incinerator	Vapor Incinerator
Facility #1	36	6	-	-	-	-	-
Facility #2	6	-	-	-	6	-	-
Facility #3	15	2	-	1	-	1	-
Facility #4	22	4	2	3	-	1	3

The new costs were also used to revise the U.S. EPA's SCR cost model that was used to estimate SCR project costs for units that cost was not provided by facilities. While only four out of the five petroleum refineries provided updated costs, the cost estimates for all five petroleum refineries increased as staff used the revised cost data provided by the facilities to update the U.S. EPA SCR cost model resulting in higher costs estimates for all SCR projects. As the box plot shows below, compared to the first cost survey, the updated revised cost increased significantly for all facilities. The plot shows the minimum, maximum, first and third quartiles, the median and the average values for each facility.

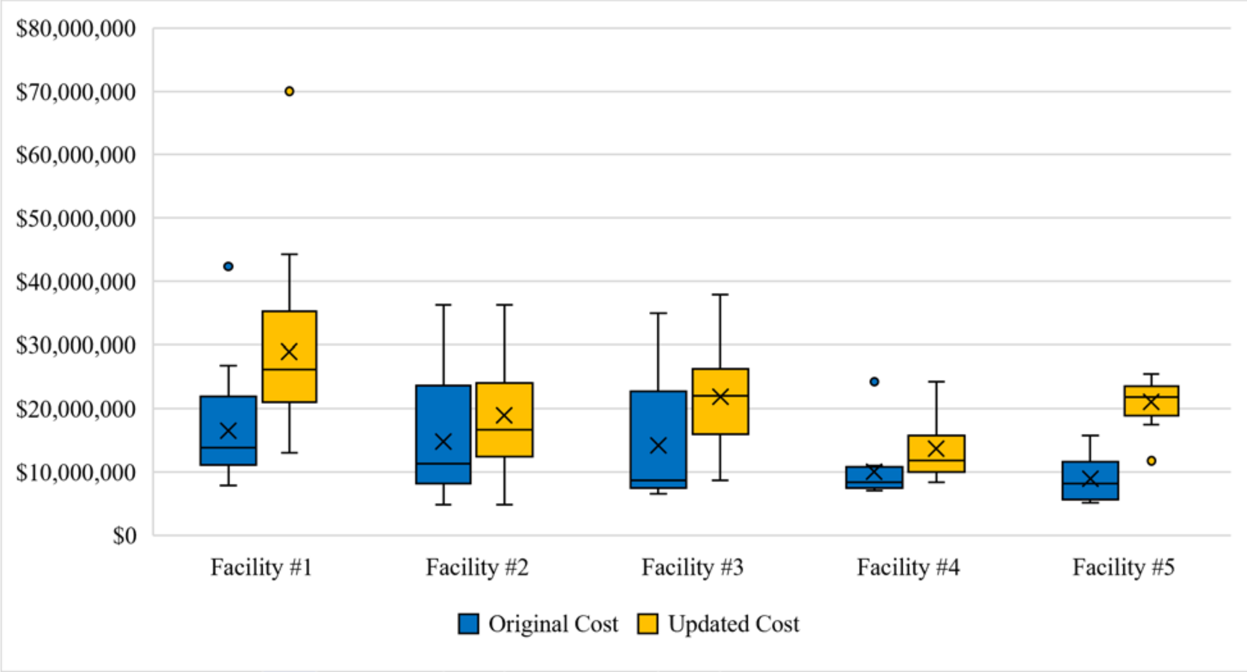


Figure 12. Original and updated cost provided by facilities

The following figure shows the number of units and range of control equipment costs that each facility provided in the second survey. Some facilities provided revisions to existing and new costs and for units. The control cost for Facility #1 was higher compared to the other facilities.

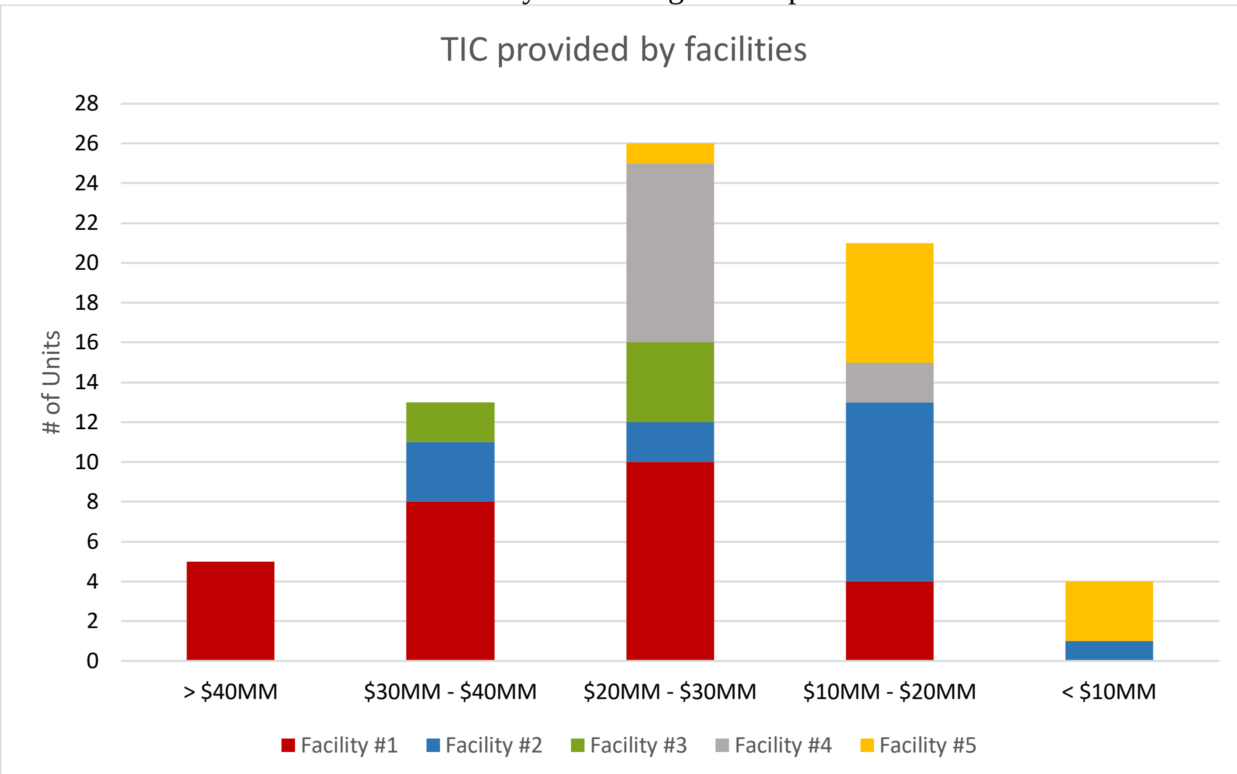


Figure 13. The number and range of control costs for each facility in the second survey

CEMS Data Survey

The CEMS survey was the third survey requested by staff from the facilities in March 2019. The CEMS data was requested for most large units (greater than 40 MMBtu/hr) as well as FCCU, coke calciner, and gas turbines. The CEMS provided staff with hourly data throughout an entire year which equated to 8,760 data points for every single unit. In addition, the CEMS data was needed to establish baseline emissions data and provided NOx concentrations, measured oxygen, flue gas stack flow rate, and fuel usage throughout the course of an entire year and amounted to nearly over 35,000 data points for a single unit. Some facilities have over 55 units, so nearly 2 million data points were provided for a single facility. Staff conducted an analysis for every single unit and every facility which gave staff insight into a unit's actual performance and operational variability.

Fuel Gas Sulfur Content Data Survey

The fuel gas sulfur survey was the fourth survey requested by staff from the facilities in March 2020. This survey was limited to the large petroleum refineries since fuel gas sulfur mainly impacts facilities utilizing refinery fuel gas, which typically has sulfur content. Refinery fuel gas streams, especially from coker units, contain sulfur compounds such as mercaptans and sulfides that are not effectively treated by the existing facilities' sulfur clean-up systems (e.g., amine systems). The sulfur in refinery fuel gas is converted to SOx and oxidized and converted to PM in the SCR due to the presence of ammonia. Staff requested this information in response to concerns regarding the high cost for meeting BACT requirements if PM emissions from the installation of SCR exceed the PM_{10} NSR thresholds. This survey provided staff detailed data on fuel gas streams, flow rate, affected units , sulfur content, existing treatment systems, and upgrade costs. The data was analyzed by staff to estimate the potential increase in PM emissions from SCR installations. As described in Chapter 1, staff collaborated with CARB and U.S. EPA to include a BACT exemption for non-ozone precursor emission increases associated with air pollution control equipment installations to comply with BARCT NOx standards. Staff will address refinery fuel sulfur content during the transition of SOx RECLAIM.

EMISSION INVENTORY AND EMISSION REDUCTIONS

The original NOx emission inventory for Petroleum Refineries was 12.4 tons per day based on a 2017 baseline. After the adoption of PR1109.1, the emissions are estimated to be reduced between 7.7 to 7.9 tons of NOx per day in accordance with the proposed implementation schedule. The table below summarizes the 2017 baseline emissions for all categories and the potential emission reductions.

Table 4-2. NOx Emission Inventory and Estimated Emission Reductions

Equipment Type	2017 NOx Baseline Emissions (tpd)	Potential NOx Emission Reductions (tpd)
Process Heaters	5.1	3.1-3.3
Boilers	2.6	2.2
Gas Turbine	1.4	0.4
SMR Heaters	1.1	0.6
FCCU	0.83	0.4
Coke Calciner	0.71	0.68
SRU/TG Incinerator	0.43	0.1
Sulfuric Acid Plants	0.1	0.0
Vapor Incinerators	0.05	0.02
10 percent Environmental Benefit	-	0.2
Total	12.4	7.7-7.9

COST-EFFECTIVENESS

California Health and Safety Code Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The cost-effectiveness of a control technology is measured in terms of the control cost in dollars per ton of air pollutant reduced is measured in terms of the control cost in dollars per ton of air pollutant reduced for each class and category of equipment. The costs for the control technology include purchasing, installation, operating, and maintaining the control technology.

The South Coast AQMD typically relies on the Discounted Cash Flow (DCF) method which converts all costs, including initial capital investments and costs expected in the present and all future years of equipment life, to a present value. Conceptually, it is as if calculating the amount of funds that would be needed at the beginning of the initial year to finance the initial capital investments but also funds to be set aside to pay off the annual costs as they occur in the future. The fund that is set aside is assumed to be invested and generates a rate of return at the discount rate chosen. The final cost-effectiveness measure is derived by dividing the present value of total costs by the total emissions reduced over the equipment life. DCF is calculated as follows:

$$Cost-effectiveness = \frac{Initial\ Capital\ Investments\ +\ (Annual\ O\&M\ Costs\ \times\ PVF)}{Annual\ Emission\ Reductions\ \times\ Years\ of\ Equipment\ Life}$$

Where:

$$PVF = \frac{(1+r)^N - 1}{r * (1+r)^{(N-1)}}$$

Where

r = real interest rate (discount rate); and
N = years of equipment life.

The present-value factor (PVF) converts a constant stream of payments made for N years into its single present-value equivalent.

Staff will also present Levelized Cash Flow (LCF) method which annualizes the present value of total costs as if all costs, including the initial capital investments, would be paid off in the future with an equal annual installment over the equipment life. LCF is

$$LCF = \left(\frac{Annualized\ Present\ Value\ of\ Total\ Costs}{Average\ Annual\ Emission\ Reductions}\right)$$

In general, DCF cost-effectiveness estimates are lower given the same interest rate and equipment life. The current DCF threshold was established in 2010 SOx RECLAIM BARCT assessment as $50,000 per ton reduced. If the threshold is inflated to represent current dollars using the Marshall and Swift Index the current values for DCF threshold would be approximately $60,000. A LCF threshold has not been established.

Control Equipment Cost Estimates

Staff relied on several sources of data to estimate the capital and installation costs and O&M costs of the control technology including the cost assumptions collected during the development of the 2015 RECLAIM NOx "shave", costs from other BARCT NOx rules for similar equipment, vendor supplied cost estimates, SCR installations, and values calculated from the U.S. EPA SCR Spreadsheet. The stakeholders indicated staff's estimates were an underestimation mainly due to the high-installation cost at refineries needed to address space constraints and the high labor costs driven by Senate Bill 54 (SB 54) which requires California refineries to hire unionized and trained construction labor for projects. As described in Chapter 1, staff conducted a survey of the affected facilities seeking total install and O&M for past or recent NOx reduction projects. Staff used the facility supplied cost data when it was provided. If no cost data was available, staff used the facility cost data to generate cost curves to estimate the cost. In the case of SCR costs, staff used the cost data provided by the facilities to update the U.S. EPA Cost Spreadsheet to estimate SCR costs. When both burner control and SCR were anticipated to be required to achieve the proposed NOx limits, the burner costs from the burner cost curve were added to the costs generated from the modified U.S. EPA Cost Spreadsheet. Staff's cost assessment also included additional costs recommended by Norton Engineering and FERCo to address annual SCR tuning and increased catalyst volume. Detailed cost information can be found in the Appendices B-G for each category of equipment. The following is a summary of the cost assumptions for boilers and heaters:

- Initial ULNB cost based on vendor supplied estimates, staff adjusted costs as follows:
  - ✓ Conducted a survey seeking burner installation costs from facilities
  - ✓ Generated a curve based on the cost estimates provided by the facilities
  - ✓ Used facility cost when provided; otherwise, the burner curve was used to estimate cost

- Initial SCR costs based on U.S. EPA SCR Cost Spreadsheet; staff altered costs as follows:
  - ✓ Conducted a survey seeking SCR installation costs from facilities
  - ✓ Modified U.S. EPA SCR Spreadsheet using costs provided by the refineries to reflect costs at California refineries
  - ✓ Used stakeholder costs when provided, otherwise used modified U.S. EPA spreadsheet
- Units requiring greater than 92% NOx reductions:
  - ✓ Added cost of ULNB to the cost of SCR
  - ✓ Alternatively, conducted cost assessment for installation of dual reactors with 25% increase to TIC to address additional costs
- Based on feedback from third party engineering consultants:
  - ✓ Added $40,000 annual costs for SCR tuning – *based on FERCo recommendation*
  - ✓ Added 30% increased cost for the catalyst - *based on Norton Engineering recommendation to account for gas velocity*
- Estimated cost per unit project to achieve proposed NOx limits ranged from ~ $10 to $80 million (present worth value)

Estimated NOx Emission Reductions

Staff used 2017 annual NOx emissions as the baseline year since the PR 1109.1 development began in 2018; therefore, 2017 emissions was latest available annual set of data. For units where the 2017 emissions are not representative of the facilities operation, e.g., a unit was in turnaround or underutilized in 2017, staff used a more representative year reflecting more normal operations. Staff utilized the NOx concentration in the flue gas corrected to the appropriate percent oxygen (boilers, heaters, flares, and coke calciner corrected to three percent oxygen on a dry bases and gas turbines and SMR heaters combined with a gas turbine corrected to 15 percent oxygen on a dry basis) as provided by the facilities. Emission reductions are calculated based on the percent reduction from the current NOx concentration in the flue gas to the proposed NOx limit applied to the 2017 emissions data for each unit. Staff estimates that implementation of PR 1109.1 will achieve between 7.7 to 7.9 tons per day of NOx. The lower range represents the maximum number of units that can potentially use the conditional NOx limits under Table 2 and the upper range represents the units that staff identified that potentially meet the conditional NOx limits under Table 2 that were assumed in the cost-effectiveness analysis. Full implementation is expected around 2034. Some smaller units may extend beyond 2034 as they are required to meet the proposed NOx limit when more than 50 percent of unit's burners are replaced.

Summary of Cost-Effectiveness by Class and Category

The following table is a summary of the cost-effectiveness for each class and category of equipment at the affect ted facilities, and the detailed analysis can be found in Appendices B-G.

Table 4-3. Summary of Cost-Effectiveness Using DCF and LCF

Equipment Category	Cost Effectiveness	
	DCF	LCF
Boilers (<20 MMBtu/hour)	-[(1)]	-[(1)]
Boilers (≥20 - <40 MMBtu/hour)	-[(1)]	-[(1)]
Boilers (≥40 - ≤110 MMBtu/hour)	$25,000	$37,000
Boilers (>110 MMBtu/hour)	$11,000	$19,000
Flares	-[(2)]	-[(2)]
FCCUs	$24,000	$65,000
FCCU Startup Heaters	-[(2)]	-[(2)]
Gas Turbines	$15,400	$42,000
Petroleum Coke Calciners	$10,000	$15,000
Process Heaters (<20 MMBtu/hour)	-[(1)]	-[(1)]
Process Heaters (≥20 - <40 MMBtu/hour)	-[(1)]	-[(1)]
Process Heaters (≥40 - ≤110 MMBtu/hour)	$50,500	$78,000
Process Heaters (>110 MMBtu/hour)	$50,000	$79,000
Sulfur Recovery Units/Tail Gas Treating Units	$39,000	$62,000
SMR Heaters	$17,000	$19,000
SMR Heaters with Gas Turbine	-[(1)]	-[(1)]
Sulfuric Acid Furnaces	-[(1)]	-[(1)]
Sulfuric Acid Startup Heater	-[(2)]	-[(2)]
Sulfuric Acid Startup Boiler	-[(2)]	-[(2)]
Vapor Incinerators	$35,000	$56,000

[(1)] Units will be required to retrofit burner control to meet future BARCT limit for category at end-of-useful life. Majority of cost will already be incurred by facility upon burner replacement

(2) Units will have a low use exemption and will not be required to install NOx control due to high cost-effectiveness and low emission reductions.

Conditional BARCT NOx Limits

As discussed in Chapter 2, staff identified several classes and categories of equipment that will have conditional limits in PR 1109.1. The table below provides an overview of cost effectiveness value to meet the Table 1 NOx limits and to meet the proposed conditional limits.

Table 4-4. Cost-effectiveness of Conditional Limits

Equipment Category	Table 1 NOx Limit (ppmv)	Proposed Conditional Limit (ppmv)	Cost Effectiveness ($/ton)	
			To Meet Table 1 NOx Limit	To Meet Conditional Limit
Boilers (>110 MMBtu/hr)	5	7.5	$75,000 -$8 Million	$0
FCCUs	2	8	$127,000	$12,000
Gas Turbines w/Natural Gas	2	2.5	$570,000	$0
Process Heaters (≥40 - ≤110 MMBtu/hour)	5	18	$53,000	$48,000
Process Heaters (>110 MMBtu/hour)	5	22	$56,000	$50,000
SMR Heaters	5	7.5	$242,000	$0
Vapor Incinerators	30	40	$100,000 - $500,000	$0

In order to ensure the conditional limit is utilized for those units with existing controls performing near the Table 1 NOx limits and it would not be cost effective to meet the Table 1 NOx limits, the proposed rule outlines conditions for using Table 2 conditional NOx limits. For example, the conditional limit is required to be in the permit by a certain date with any application to make minor modifications to be submitted by a certain date and cannot be a unit whose projected emission reductions are high. For more detailed discussion and analysis of the conditional limits can be found in the appendices of this staff report for each of the affected classes.

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments relative to ozone, carbon monoxide, sulfur oxides, oxides of nitrogen, and their precursors. Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option. An incremental cost-effectiveness analysis has been conducted in concert with the BARCT analysis for each class and category. The figure below shows an overview of the California Health and Safety Code Section BARCT requirements.

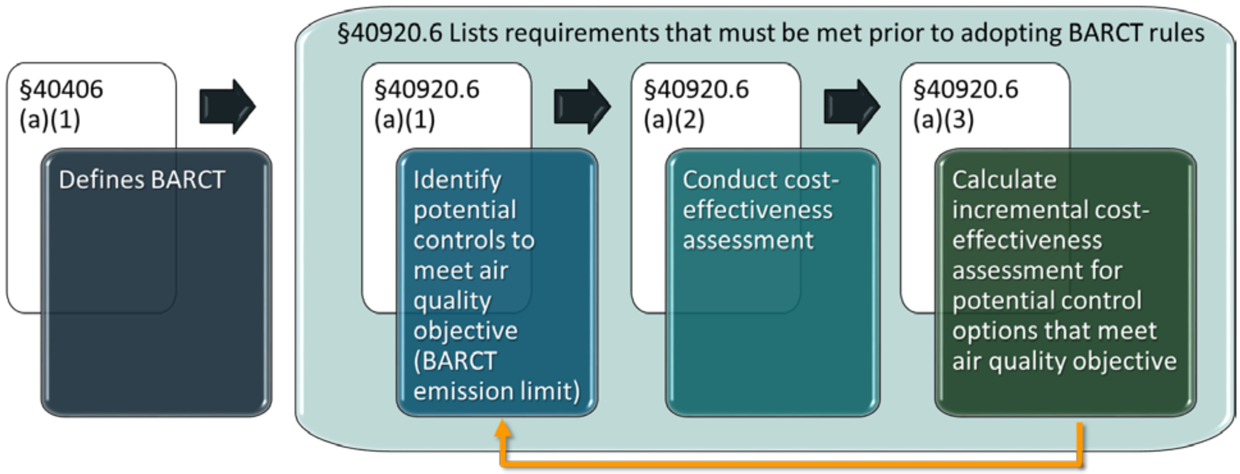


Figure 14. California Health and Safety Code Section BARCT Requirements

Step 1: Identify Control Options

In the first step, staff identifies one or more potential control options which achieves the emission reduction objectives for the regulation. For PR 1109.1, the "emission reduction objectives" is to establish a NOx emission limit representative of BARCT and by definition of BARCT staff is seeking the "maximum degree of reduction achievable by each class or category of source, considering the environmental, energy, and economic impacts."

Step 2: Determine Cost-Effectiveness

Staff calculates the cost-effectiveness, which is the cost in dollars, of the potential control option divided by emission reduction potential, in tons, of the potential control option.

$$Cost - Effectiveness = \frac{Cost}{Emission\ Reductions}$$

If the potential control option that will provide the maximum degree of reduction achievable is $50,000 per ton of NOx reduced or less, the next most stringent option may be selected as the potential control option, based on the 2016 AQMP cost-effectiveness threshold. If the most stringent potential control option is not cost-effective, staff calculates the cost-effectiveness of the next potential control option that will provide the maximum degree of reductions achievable.

Step 3: Calculate Incremental Cost-Effectiveness

Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option.

$$Incremental\ Cost - Effectiveness = \frac{Cost_A - Cost_B}{Emission\ Reductions_A - Emission\ Reductions_B}$$

This step requires that the incremental cost-effectiveness be calculated for all potential control options identified in Step 1, even if the cost-effectiveness was not evaluated in Step 2. Evaluation of the incremental cost-effectiveness can identify a different NOx limit than Step 2 if the difference in reductions is small relative to the difference in cost between potential control options. If the incremental cost-effectiveness reveals that a more stringent control option has a high incremental cost-effectiveness, a less stringent NOx limit will be assessed and can be determined to be BARCT.

Although there is no threshold for evaluating incremental cost-effectiveness, staff agrees that a lower NOx limit with an incremental cost-effectiveness well above $50,000 per ton of NOx reduced is an indication that the more stringent control option is not incrementally cost-effective. The detailed incremental cost-effectiveness analysis for each class and category is presented in Appendices B – G.

BARCT EQUIVALENT COMPLIANCE PLANS

PR1109.1 seeks to maximize NOx emission reductions by imposing stringent NOx limits during the operation of refinery equipment resulting in 7-8 tons per day NOx reductions. These reductions are crucial in meeting the ambient air quality standards for ozone and PM since NOx is a major constituent of ozone and precursor to PM. By meeting the standards, the public health of the region will improve as premature deaths are avoided, asthma cases are avoided, and number of loss workdays are avoided. Cleaner air has positive impacts on visibility, erosion, animal and plant life, as well as a more healthy, productive society.

Due to the high number of affected equipment, high costs to install controls ($10 million to $70 million per project), competing demand for resources (e.g., trained labor pool, construction material), and concerns for long downtimes and disruptions affecting fuel supply, a staggered compliance schedule is being proposed. Flexibility is necessary to ensure a realistic and successful implementation while achieving anticipated emission reductions and providing cost savings. First, it was determined that some projects, due to a variety of reasons such as high costs and low reductions, would be extremely not cost effective individually even though BARCT determinations are calculated based on class and category. These outliers were removed from the cost-effective calculation for the determination of the BARCT limit and evaluated for a concentration limit up to when it would be cost effective. However, these "conditional" limits could only be applied to those projects satisfying certain criteria, such as equipment with no control installed post December 2015 when the RECLAIM shave was approved. Most eligible equipment is already controlled with no high emission reduction potential; therefore, facilities will experience a cost savings from avoiding an expensive SCR project and accepting a limit for the equipment operating at or near the conditional limit resulting in no additional or limited expense to further control, modify, tune or upgrade.

I-Plans are designed to provide facilities the ability to implement projects that best suit the timing of the projects to comply with emission reduction targets. This helps companies' better budget and plan so projects could occur during scheduled turnarounds, which provides a cost savings from not having to accelerate planning and schedule additional unplanned turnarounds. Additional turnarounds result in more costs from an additional lengthy design process and logistics, as well as facility downtime, loss of production and sales, and overall impact on the regional and state fuel supply that, in turn, can affect downstream businesses dependent on petroleum products. Figure below shows the percentage of required NOx reductions for implementations of I-Plans based on compliance schedule in Table 6 of PR 1109.1. Note that the reductions showed in the chart are based on estimated emission reductions from all equipment in the rule and 75% of the targeted emission reductions could be achieved in 2027.

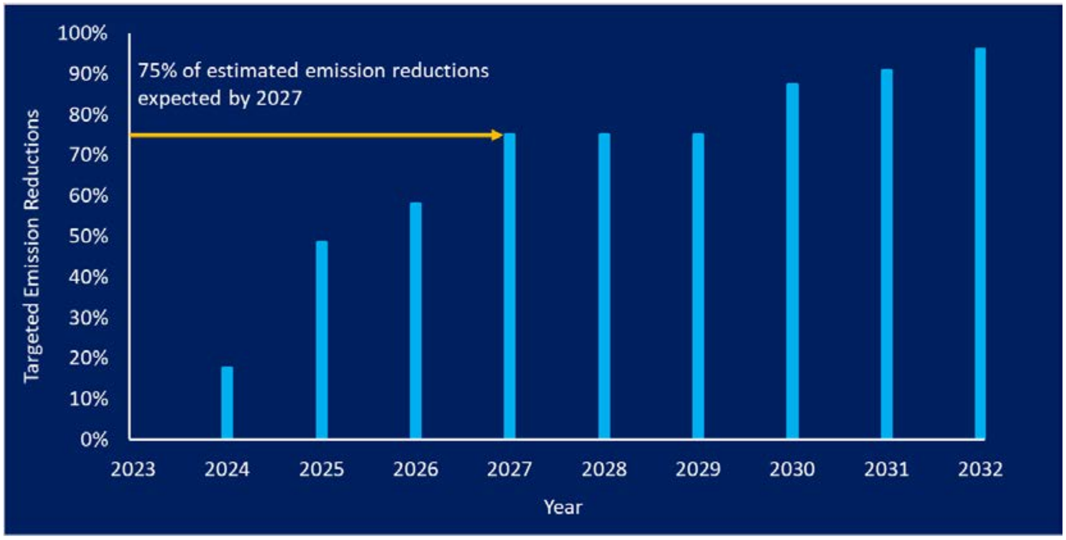


Figure 15. Percentage of Required NOx Reductions for Implementation of I-Plans

B-Plans, like the conditional limits, provide the facilities flexibility in deciding which projects are more cost effective to over-control and which overly expensive projects could be re-designed to be avoid high costs and yet meet the overall BARCT equivalent emission reductions in the aggregate. While to over-control one piece of equipment will be more costs, facilities under the B-Plan can calculate and decide whether the under-control of another piece of equipment is worth the trade-off. Most likely, cost will be a major factor in making that decision.

B-Caps are required to meet BARCT equivalent emission reduction targets but provide the flexibility in the day-to-day operation of the refinery equipment under a mass cap as opposed to stringent individual concentration limits. The overall emission reductions are the same but, similar to the B-Plan, facilities have the ability to decide which equipment will operate at certain levels in order to meet the required target. These decisions are likely to be made based on which equipment is most cost effective to install and operated controls, and which equipment is best to be shutdown and replaced, or just shutdown. Older equipment tends to be more expensive to retrofit and control, so shutting down or replacing will likely be less cost overall and more cost effective when seeking NOx emission reductions.

RULE ADOPTION RELATIVE TO COST-EFFECTIVENESS

On October 14, 1994, the Governing Board adopted a resolution that requires staff to address whether rules being proposed for amendment are considered in the order of cost-effectiveness. The 2016 AQMP ranked, in the order of cost-effectiveness, all the control measures for which costs were quantified. It is generally recommended that the most cost-effective actions be considered first. PR 1109.1 implements Control Measure CMB-05 which was ranked sixth in cost-effectiveness in the 2016 AQMP ranked Control Measure CMB-05.

SOCIOECONOMIC ASSESSMENT

The Draft Socioeconomic Impact Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, and Proposed Amended Rule 2005 – New Source Review for RECLAIM was released on September 7, 2021, for a 60-day public review period.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's Certified Regulatory Program (Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l); codified in South Coast AQMD Rule 110), the South Coast AQMD is lead agency for the proposed project, which is comprised of Proposed Rules 1109.1 and 429.1, Proposed Amended Rules 1304 and 2005, and Proposed Rescinded Rule 1109. CEQA Guidelines Section 15187 requires an environmental analysis to be performed when a public agency proposes to adopt a new rule or regulation requiring the installation of air pollution control equipment or establishing a performance standard, which is the case with the proposed project. The South Coast AQMD has prepared a Subsequent Environmental Assessment (SEA) for the proposed project, which is a substitute CEQA document pursuant to CEQA Guidelines Section 15252, prepared in lieu of a Subsequent Environmental Impact Report. The SEA contains the environmental analysis required by CEQA Guidelines Section 15187 and tiers off of the December 2015 Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (referred to as NOx RECLAIM) and the March 2017 Final Program Environmental Impact Report (EIR) for the 2016 Air Quality Management Plan as allowed by CEQA Guidelines Sections 15152, 15162, 15168 and 15385. The Draft SEA was released for a 45-day public review and comment period to provide public agencies and the public an opportunity to obtain, review, and comment on the environmental analysis. Comments made relative to the analysis in the Draft SEA and responses to the comments will be included in the Final SEA.

Draft Findings Under California Health and Safety Code Section 40727

Requirements to Make Findings

California Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the South Coast 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.

Necessity

Proposed Rule 1109.1 is needed to establish BARCT requirements for petroleum refineries and related operations, including facilities that will be transitioning from RECLAIM to a command-and-control regulatory structure. For this rule, affected facilities include asphalt plants, biofuel plants, hydrogen production plants, petroleum coke calcining facilities, sulfuric acid plants and sulfur recovery plants. In addition, Assembly Bill 617 requires facilities subject to a cap-and-trade program to be evaluated for BARCT.

Authority
The South Coast AQMD Governing Board has authority to adopt amendments to Proposed Rule 1109.1 pursuant to the California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, and 41508.

Clarity
Proposed Rule 1109.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

Consistency
Proposed Rule 1109.1 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

Non-Duplication
Proposed Rule 1109.1 will not impose the same requirements as any existing state or federal regulations. The proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference
In drafting Proposed Rule 1109.1, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: Health and Safety Code Sections 39002, 40000, 40001, 40702, 40440(a), 40440(b), 40440(c), 40725 through 40728.5, and 41508.

COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, the South Coast AQMD is required to perform a comparative analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to combustion equipment subject to PR 1109.1. The comparative analysis for PR 1109.1 can be found in the following two tables below.

Table 4-5. Comparative Analysis for PR 1109.1 with South Coast AQMD Rules

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
Applicability	Units at petroleum refineries and facilities with related operations to petroleum refineries, including Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, petroleum coke calcining facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants	Facilities regulated under the NOx RECLAIM program (SCAQMD Reg. XX)	Flares that require a SCAQMD permit at non-refinery facilities, including, but not limited to, oil and gas production facilities, wastewater treatment facilities, landfills, and organic liquid handling facilities	Stationary gas turbines, 0.3 megawatt (MW) and larger. • Not applicable to stationary gas turbines subject to Rule 1135 located at petroleum refineries, landfills, or publicly owned treatment works; or fueled by landfill gas	Boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations	Ovens, dryers, dehydrators, heaters, kilns, calciners, furnaces, crematories, incinerators, heated pots, cookers, roasters, fryers, closed and open heated tanks and evaporators, distillation units, afterburners, degassing units, vapor incinerators, catalytic or thermal oxidizers, soil and water remediation units and other combustion equipment with nitrogen oxide emissions that require a District permit and are not specifically required to comply with a nitrogen oxide emission limit by other District Regulation XI rules
Requirements	NOx Limits at 24-hour Rolling Averaging Time unless specified otherwise: • Boilers <40 MMBtu/hr: 40 ppmv/ 5 ppmv @ replacement of 50% or more of the burners in a boiler or 50% or more of the heat input in a boiler • Process Heaters <40 MMBtu/hour: 40 ppmv/ 9 ppmv @ replacement of 50% or more of the burners in a process heater or 50% or more of the heat input in a process heater • Boilers and Process Heaters ≥40	**<u>RECLAIM 2005:</u>** • Boilers and Heaters <20 MMBtu/hr:12 ppmv • Boilers and Heaters ≥20–<40 MMBtu/hr: 9 ppmv • Boilers and Heaters ≥40–≤110 MMBtu/hr: 25 ppmv • Boilers and Heaters >110 MMBtu/hr: 5 ppmv • Petroleum Refining, Calciner: 30 ppmv • Petroleum Refining, FCCU: 85% reduction for FCCU and CO Boiler **<u>RECLAIM 2015:</u>** • Boilers and Heaters ≥40 MMBtu/hr: 2 ppmv @ 3% O_2 • Petroleum Refining, Calciner: 10 ppmv	• Non-Refinery Flares: Replacement with 20 ppmv flare (0.025 lb/MMBtu) if throughput capacity > 5%	For engines installed prior to January 1, 2012 • 12.7 g/hp-hr when max engine speed < than 130 rpm • 34 · $n^{-0.2}$ g/hp-hr) when 130 £ max engine speed < 2,000 rpm, where n is max engine speed; and • 7.3 g/hp-hr when max engine speed > 2,000 rpm For engines installed on or after January 1, 2012 and before January 1, 2016 • 10.7 g/hp-hr when max engine speed < 130 rpm; • 33 · $n^{-0.23}$ g/hp-hr) when 130 £ max engine speed < 2,000 rpm, where n is max engine speed; and	• Boilers and Heaters ≥75 MMBtu/hr: 5 ppmv • Boilers and Heaters <75 MMBtu/hr: 9 ppmv	• Calciner and Kiln (≥1200°F): 60 ppmv at 3% O_2 <u>**or**</u> 0.073 lb/MMBtu • Incinerator, Afterburner, Remediation Unit, and Thermal Oxidizer: 60 ppmv or 0.073 lb/MMBTU

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
	MMBtu/hour: 5 ppmv @ 3% O_2 • FCCU: 2 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 5 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • Flares: 20 ppmv @ 3% O_2 • Gas Turbines fueled with Natural Gas: 2 @ 15% O_2ppmv • Gas Turbines fueled with Gaseous Fuel other than Natural Gas: 3 ppmv @ 15% O_2 • Petroleum Coke Calciner: 5 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 10 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • SMR Heaters: 5 ppmv @ 3% O_2 • SMR Heaters with Gas Turbine: 5 ppmv @ 15% O_2 • SRU/TG Incinerators: 30 ppmv @ 3% O_2 • Sulfuric Acid Furnaces: 30 ppmv @ 3% O_2 and 365-day Rolling Averaging Time • Vapor Incinerators: 30 ppmv @ 3% O_2	• Petroleum Refining, FCCU: 2 ppmv @ 3% O_2, dry • Refinery Gas Turbines: 2 ppmv @ 15% O_2, dry • Sulfur Recovery Units/Tail Gas Incinerator: 2 ppmv NOx @ 3% O_2, dry		• 5.7 g/hp-hr) when max engine speed > 2,000 rpm. For engines installed on or after January 1, 2016, • 2.5 g/hp-hr when max engine speed < 130 rpm; • $6.7 \cdot n^{-0.20}$ g/hp-hr) when 130 £ max engine speed < 2,000 rpm, where n is max engine speed; and • 1.5 g/hp-hr when max engine speed > 2,000 rpm.		
Reporting	Submit all source test reports, including the source test results and a description of the unit tested, to the Executive Officer within 60 days of completion of the source test	• Daily electronic reporting for major sources • Monthly to quarterly reporting for large sources and process units • Quarterly Certification of Emissions Report and Annual Permit Emissions Program for all units	Annual report	• Comply with SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions to demonstrate compliance with the NOx emissions limits of this rule • Determine eligibility of the low-use exemption for each stationary gas turbine	None	None

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
				annually and report to the Executive Officer no later than March 1 following each reporting year		
Monitoring	• For a unit with a rated heat input capacity of greater than or equal to 40 MMBtu/hour in a Former RECLAIM Facility install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements • For a unit with no CEMS, conduct a source test, with a duration of at least 60 minutes but no longer than 120 minutes • Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for units without CEMS under B-Cap • If source test is applicable, conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program • For a unit required to perform a source test every 36 months, perform diagnostic emissions checks of NOx, CO, and O_2 emissions with a portable NOx, CO, and	• A continuous in-stack NOx monitor for major sources • Source testing once every 3 years for large sources • Source testing once every 5 years for process units	Install and operate a fuel meter for each gas or vapor, excluding pilot gas, routed to every flare or flare station	• Conduct monitoring pursuant to SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions • Each stationary gas turbine with a catalytic control device shall conduct source testing or utilize an ammonia continuous emission monitoring system certified under an approved SCAQMD protocol to demonstrate compliance with the ammonia emission limit • Installation of an ammonia continuous emission monitoring system certified under an approved SCAQMD protocol if an extension is requested beyond 12 months to comply with the ammonia emission limits • Each stationary gas turbine operating without a continuous emission monitoring system and emitting 25 tons or more of NOx per calendar year shall perform source tests to demonstrate compliance with the NOx emission limits at least once every calendar year. • Each stationary gas turbine operating without a continuous emission monitoring system and	• Any unit(s) with a rated heat input capacity greater than or equal to 40 million Btu per hour and an annual heat input greater than 200 x 109 Btu per year shall have a continuous in-stack nitrogen oxides monitor or equivalent verification system in compliance with Rule 218 and Rule 218.1 • For air pollution control equipment with ammonia emissions: 1) Conduct quarterly a source test to demonstrate compliance with the ammonia emission limit, according to the procedures in District Source Test Method 207.1 for Determination of Ammonia Emissions from Stationary Sources, during the first 12 months of unit operation and thereafter, except that source tests may be conducted annually within 12 months thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit **OR** 2) Utilize an ammonia Continuous Emissions Monitoring System (CEMS) certified under an approved South Coast AQMD protocol to demonstrate compliance with the ammonia emission limit • Compliance with the NOx and CO emission requirements shall be determined using a South Coast AQMD approved contractor under the Laboratory	• Owners or operators of units shall determine compliance with the applicable emission limit using a District approved test protocol • Install and maintain in service non-resettable, totalizing, fuel meters for each unit's fuel(s) for a unit complying with applicable limit using pounds per million BTU

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
	O_2 analyzer every 365 days or every 8760 operating hours, whichever occurs earlier • Provisions for Source Test Schedule for Units with and without Ammonia Emissions in the Exhaust			emitting less than 25 tons shall perform source tests to demonstrate compliance with the NOx emission limits at least once every three calendar years. • Each stationary gas turbine with a catalytic control device not utilizing an ammonia continuous emission monitoring system shall conduct source tests quarterly to demonstrate compliance during the first twelve months of operation of the catalytic control device and every calendar year thereafter when four consecutive source tests demonstrate compliance with the ammonia emission limit. If a source test is failed, four consecutive quarterly source tests shall demonstrate compliance with the ammonia emissions limits prior to resuming source tests annually	Approval Program according to specific procedures: (A) Every three years for units with a rated heat input capacity greater than or equal to 10 million Btu per hour, except for units subject to paragraph (c)(5) (B) Every five years for units with a rated heat input capacity less than 10 million Btu per hour down to and including 5 million Btu per hour • Diagnostic emission checks of NOx emissions with a portable NOx, CO, and oxygen analyzer according to the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen	
Recordkeeping	• Operating log • Maintain daily records of mass emissions, in pounds (lbs) per day, from all units included in an approved B-Cap • Keep and maintain the following records on-site for five years and make them available to the Executive Officer upon request: (A) CEMS data; (B) Source tests reports; (C) Diagnostic emission checks; and (D) Written logs of startups, shutdowns,	• Quarterly log for process units • < 15-min. data = min. 48 hours; ≥ 15-min. data = 3 years (5 years if Title V) • Maintenance & emission records, source test reports, RATA reports, audit reports and fuel meter calibration records for Annual Permit Emissions Program = 3 years (5 years if Title V)	• Maintain records of annual throughput attributed to source testing and utility pipeline curtailment • Maintain a copy of the manufacturer's, distributor's, installer's or maintenance company's written maintenance schedule and instructions • Retain all written or electronic records for at least five years and make them available no later than five business days from date requested	• Conduct recordkeeping pursuant to SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions • All records shall be maintained at the facility for a period of two years and made available to SCAQMD staff upon request. • Maintain a gas turbine operating log that includes, on a daily basis, the actual start-up and shut-down times; total hours of	• Records of all monitoring data shall be maintained for a rolling twelve-month period of two years (five years for Title V facilities) and shall be made available to South Coast AQMD personnel upon request • The owner or operator of any unit(s) selecting the tune-up option shall maintain records for a rolling 24-month period verifying that the required tune-ups have been performed	• Records of source tests shall be maintained for ten years and made available to District personnel upon request • Maintain on site at the facility where the unit is being operated a copy of the manufacturer's, distributor's, installer's or maintenance company's written maintenance schedule and instructions and retain a record of the maintenance activity for a period of not less than three years

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
	and breakdowns, all maintenance, service and tuning records, and any other information required by this rule • Data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours			operation; type and quantity of fuel used (liquid/gas); cumulative hours of operation to date for the calendar year		• Maintain on site a copy of all documents identifying the unit's rated heat input capacity for as long as the unit is retained on-site

Table 4-6. Comparative Analysis for PR 1109.1 with Federal Requirements

	PR 1109.1	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK
Applicability	Units at petroleum refineries and facilities with related operations to petroleum refineries, including Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, petroleum coke calcining facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants	Steam generating units that commenced construction, modification, or re-construction after 6/19/1984 and that has a heat input capacity of >29 MW (100 MMBtu/hr)	Gas turbines with heat input of ≥10 MMBtu/hr that commenced construction, modification or re-construction on or before 2/18/2005	Fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. • For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008	Gas turbines with heat input of ≥10 MMBtu/hr that commenced construction, modification or re-construction after 2/18/2005
Requirements	NOx Limits at 24-hour Rolling Averaging Time unless specified otherwise: • Boilers <40 MMBtu/hr: 40 ppmv/ 5 ppmv @ replacement of 50% or more of the burners in a boiler or 50% or more of the heat input in a boiler • Process Heaters <40 MMBtu/hour: 40 ppmv/ 9 ppmv @ replacement of 50% or more of the burners in a process heater or 50% or more of the heat input in a process heater • Boilers and Process Heaters ≥40 MMBtu/hour: 5 ppmv @ 3% O_2 • FCCU: 2 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 5 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • Flares: 20 ppmv @ 3% O_2 • Gas Turbines fueled with Natural Gas: 2 @ 15% O_2 ppmv • Gas Turbines fueled with Gaseous Fuel other than Natural Gas: 3 ppmv @ 15% O_2 • Petroleum Coke Calciner: 5 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 10 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • SMR Heaters: 5 ppmv @ 3% O_2 • SMR Heaters with Gas Turbine: 5 ppmv @ 15% O_2 • SRU/TG Incinerators: 30 ppmv @ 3% O_2	NOx limits (30-day rolling average): • Natural gas and distillate oil, except duct burners in combined cycle systems: 43 ng/J (low heat release), 86 ng/J (high heat release) • Residual Oil: 130 ng/J (low heat release), 170 ng/J (high heat release) • Coal: 210 ng/J (mass-feed stoker), 260 ng/J (spreader stoker and fluidized bed combustion), 300 ng/J (pulverized coal), 260 ng/J (Lignite), 340 ng/J (Lignite mined in North Dakota, South Dakota or Montana and combusted in a slag tap furnace), 210 ng/J (coal-derived synthetic fuels) • Duct burner in a combined cycle system: 86 ng/J (natural gas and distillate oil), 170 ng/J (residual oil) • Affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of ≤26 ng/J with wood, municipal-type solid waste, or other solid fuel, except coal: 130 ng/J • Affected facility that commenced construction after July 9, 1997: 86 ng/J (combusts coal, oil, or natural gas, or any combination of the three)	Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired: • NOx Concentration (percent by volume @ 15% O_2) = 0.0150* (14.4/Y) + F where: Y = Manufacture's rated heat input F = NOx emission allowance for fuel-bound nitrogen	FCCU & FCU: • NOx: 80 ppmv, 7-day rolling average • CO: 500 ppmv, hourly average Process heaters > 40 MMBtu/hr (30 day rolling average): • 40 ppmv or 0.040 lb/MMBtu for natural draft process heaters • 60 ppmv or 0.060 lb/MMBtu for forced draft process heaters • 150 ppmv or Equation 3 for co-fired natural draft process heaters • 150 ppmv or Equation 4 for co-fired forced draft process heaters For flares, develop and implement a written flare management plan *All emission limits are dry @ 0% excess air	NOx limit @ 15% O_2: • new, firing natural gas, electric generating ≤50 MMBtu/hr – 42 ppm • new, firing natural gas, mechanical drive ≤50 MMBtu – 100 ppm • new, firing natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 25 ppm • new, modified, or reconstructed, firing natural gas >850 MMBtu/hr – 15 ppm • new, firing fuels other than natural gas, electric generating ≤50 MMBtu/hr – 96 ppm • new, firing fuels other than natural gas, mechanical drive ≤50 MMBtu/hr – 150 ppm • new, firing fuels other than natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 74 ppm • new, modified, or reconstructed, firing fuels other than natural gas >850 MMBtu/hr – 42 ppm • modified or reconstructed ≤50 MMBtu/hr – 150 ppm • modified or reconstructed, firing natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 42 ppm • modified or reconstructed, firing fuels other than natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 96 ppm

	PR 1109.1	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK
	• Sulfuric Acid Furnaces: 30 ppmv @ 3% O_2 and 365-day Rolling Averaging Time Vapor Incinerators: 30 ppmv @ 3% O_2				
Reporting	Submit all source test reports, including the source test results and a description of the unit tested, to the Executive Officer within 60 days of completion of the source test	• Performance test results, notification of the initial startup, design heat input capacity, fuels to be combusted, a copy of any federally enforceable requirement that limits the annual capacity factor, annual capacity factor, emerging technology used for SO_2 emissions; reports of excess emissions	• Semi- annual reports of excess emissions and monitor downtime	• Semi- annual reports of excess emissions and monitor downtime. Notification of the specific monitoring provisions the owner or operator intends to comply with.	• Semi- annual reports of excess emissions and monitor downtime. Annual performance test results.
Monitoring	• For a unit with a rated heat input capacity of greater than or equal to 40 MMBtu/hour in a Former RECLAIM Facility install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements • For a unit with no CEMS, conduct a source test, with a duration of at least 60 minutes but no longer than 120 minutes • Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for units without CEMS under B-Cap	• Performance tests with either of following Test Methods: – Method 19, Method 3A or 3B, Method 5, 5B, or 17, Method 5, Method 17, Method 1, Method 9, Method 7E, Method 7,7A, 7E, Method 320 • Quarterly accuracy determinations and daily calibration drift tests for CEMS	• Performance test with either of following Test Methods: – EPA Method 20; ASTM D6522-00; EPA Method 7E and either EPA Method 3 or 3A; sampling traverse points following Method 20 or Method 1, and sampled for equal time intervals • A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel (averaged over one hour) or CEMS consisting of NOx and O_2 monitors for stationary gas turbines that commenced construction, reconstruction, or modification after October 3, 1977, but before July 8, 2004, and which uses	• Initial performance test with either of following Test Methods: – Method 1 of Appendix A-1 to part 60, Method 2 of appendix A-1 to part 60, Method 3, 3A, or 3B of appendix A-2 to part 60, Method 5, 5B, or 5F of appendix A-3 to part 60, Method 7, 7A, 7C,7D or 7E of appendix A-4 to part 60, Method 10, 10A, or 10B of appendix A-4 to part 60, Method 6, 6A, or 6C of appendix A-4 to part 60, Method 15 or 15A of appendix A-5 to part 60, Method 16 of appendix A-6 to part 60, Method 11, Method 18 of appendix A-6 to part 60, Method 2, 2A, 2B, 2C or 2D of appendix A–2 to part 60	• Initial performance test with either of following Test methods: – EPA Methods 7E and 3A, EPA Method 20, EPA Method 19 • A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or CEMS for stationary gas turbines using water or steam injection (hourly average) • Annual performance tests or continuous monitoring for turbines without water or steam injection

	PR 1109.1	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK
	• If source test is applicable, conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program • For a unit required to perform a source test every 36 months, perform diagnostic emissions checks of NOx, CO, and O_2 emissions with a portable NOx, CO, and O_2 analyzer every 365 days or every 8760 operating hours, whichever occurs earlier Provisions for Source Test Schedule for Units with and without Ammonia Emissions in the Exhaust		water or steam injection to control NOx emissions (averaged over one hour)	– ASTM D1945–03, ASTM D1946–90, ASTM D6420–99, ASTM UOP539–97 – ASME MFC–3M–2004, ANSI/ASME MFC–4M–1986, ASME MFC–6M–1998, ASME/ANSI MFC–7M–1987, ASME MFC–11M–2006, ASME MFC–14M–2003, ASME MFC–18M–2001, ANSI/ASME–MFC–5M–1985, ASME/ANSI MFC–9M–1988, ASME MFC–16–2007, ASME MFC–22–2007 – AGA Report No. 3, Part 1, AGA Report No. 3, Part 2, AGA Report No. 11, AGA Report No. 7 – API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 – ISO 8316 – ASTM D240–02, ASTM D1826–94, ASTM D1945–03, ASTM D1946–90, ASTM D3588–98, ASTM D4809–06, ASTM D4891–89 – GPA 2261–00, GPA 2172–09 • FCCU & FCU subject to a PM limit: continuous parameter monitor systems, bag leak detection system, CEMS, or an instrument for continuously monitoring the opacity of emissions • FCCU & FCU subject to NOx, SO_2 or CO limit: CEMS • Process heaters with a NOx limit: CEMS • Process heaters with a mass-based or heating value-based limit NOx limit: Fuel gas flow and fuel oil flow monitors • CPMS flow monitoring for flares	

	PR 1109.1	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK
Recordkeeping	• Operating log • Maintain daily records of mass emissions, in pounds (lbs) per day, from all units included in an approved B-Cap • Keep and maintain the following records on-site for five years and make them available to the Executive Officer upon request: (A) CEMS data; (B) Source tests reports; (C) Diagnostic emission checks; and (D) Written logs of startups, shutdowns, and breakdowns, all maintenance, service and tuning records, and any other information required by this rule Data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours	• Performance testing; emission rates; daily records of the amounts of each fuel combusted; calculations of the annual capacity factor for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste; nitrogen content; opacity; hours of operation. Records are required to be maintained for 2 years	• Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence and duration of any startup, shutdown, or malfunction	• Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence and duration of any SSM; flare management plan; conformance with bag leak detection system O&M; bag leak detection system alarms and actions; FCCU & FCU coke-burn off rate and hours of operation; records of emissions > 500 lbs SO_2; qualification for exemptions; time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods	• Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence and duration of any startup, shutdown, or malfunction

REFERENCES

Draft Final Staff Report of Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM. South Coast AQMD, December 4, 2015.

Dynamic Control of SCR Minimum Operating Temperature. C. A. Lockert, P. C. Hoeflich, and L. S. Smith. Power-Gen International, December 2009.

APPENDIX A NOX FORMATION AND CONTROL TECHNOLOGIES

NOx Formation

The combustion of fuels results in NOx emissions which refers collectively to oxide of nitrogen (NO) and nitrogen dioxide (NO_2). There are three prominent formation mechanisms by which NOx is generated in combustion processes: Thermal NOx, Fuel NOx, and Prompt NOx. Most combustion control techniques are designed around the concept of reducing thermal and/or fuel NOx. Post-combustion techniques reduce NOx in the flue gas regardless of the formation mechanism.

Thermal NOx Formation

Thermal NOx is formed through a high temperature reaction (hence, the name "Thermal" NOx) between molecular nitrogen and oxygen present in the combustion air by the well-known Zeldovich mechanism (reaction 1). The formation of thermal NOx is dependent upon the molar concentrations of nitrogen and oxygen and the temperature of combustion. Therefore, most NOx techniques that control thermal NOx formation at the source focus on reducing peak flame temperature or concentrations of the reactants (N_2 and O_2). Combustion at temperatures below 2,400°F forms lower concentrations of NOx, whereas thermal NOx formation increases exponentially at temperatures above 2,600°F and linearly with increases in residence time.

$N_2 + O_2 \rightarrow NO, NO_2$ (1)

Fuel NOx Formation

Fuel NOx is formed through the reactions of nitrogen-containing organic compounds in the fuel (hence, the name "Fuel" NOx) with oxygen in the combustion air. The bond between atoms of nitrogen and other chemical elements, such as carbon, in fuels is not as strong as the nitrogen bond found in molecular nitrogen (i.e., triple, N≡N). The overall reaction is as follows:

$R\text{-}N + O_2 \rightarrow NO, NO_2, CO_2, H_2O$, trace species (2)

Fuel NOx formation is typically not a concern in refinery equipment that fire natural gas or refinery fuel gas because they contain little or no fuel-bound nitrogen. Molecular nitrogen (N_2) in natural gas does not contribute significantly to fuel NOx formation because of the stronger nitrogen inter-bond than those of nitrogen compounds. Fuel NOx is not a concern for gaseous fuels like natural gas, propane, or refinery gas, which normally have no nitrogen-containing organic compounds. Fuel NOx is not a major contributor to overall NOx emissions from refinery equipment and may be important when oil, coal, or waste fuels (e.g., landfill gas) are used, which may contain significant amounts of organically bound nitrogen. However, fuel NOx is a concern if the equipment burns distillates or residual oils because these fuels contain nitrogen-bearing species.

Prompt NOx Formation

Prompt NOx formation occurs when nitrogen-containing fuels are burned in fuel-rich combustion conditions through a relatively fast reaction (hence, the name "Prompt" NOx) between nitrogen, oxygen, and hydrocarbon radicals (reaction 3).

$R + O_2 + N_2 \rightarrow NO, NO_2, CO_2, H_2O$, trace species (3)

Prompt NOx is generally an important mechanism in lower-temperature combustion processes, but it is less important compared to thermal NOx formation at the higher temperatures which are common in many refinery combustion units.

Fluidized Catalytic Cracking Units (FCCU) NOx Formation

The FCCU is a unique process where NOx formation occurs as a result of coke burn off from the catalyst in the regenerator section of the unit. The coke on the catalyst is the result of the hydrocarbon feed (vacuum gas oil) to the FCCU which contains nitrogen-bound species that form precursors such as ammonia and cyanide as the coke is burned off the catalyst. These precursors will further convert to NOx depending on regenerator design and operating conditions. Unlike other refinery combustion equipment, thermal NOx is not a significant factor in the regenerator since operating temperature is <1,500 ºF. All the FCCUs within the South Coast Air District currently operate in full burn mode, so NOx contribution from the CO boiler burners is not a concern – CO boilers are operated as a heat recovery device only and are unfired.

Fuel Type

Most, if not all, fuels combusted at a refinery are gaseous fuels and consist of various fuel types. Fuel type has an impact on NOx emissions due to varying higher heating value (HHV) content of the fuel. There are several fuel types that are used in the combustion equipment impacted by PR 1109.1. Refinery fuel gas and natural gas are the predominant fuels used at refineries within the South Coast AQMD. Most of the refinery heaters and boilers are permitted to use both refinery gas and natural gas. One refinery operates a CO boiler that combust CO-rich off-gas from the FCC in addition to refinery gas and natural gas. For the purposes of the BARCT assessment, combustion equipment is further segregated into separate categories based on their fuel type, overall process type, and specific application.

Refinery Fuel Gas

Refinery fuel gas (RFG) is a by-product of the petroleum refining process and the predominant fuel for most refinery combustion equipment. RFG is comprised of methane, olefins, hydrogen, and H_2S, and its composition varies amongst the five refineries. Varying composition of RFG results in variations in HHV which can potentially impact the formation of NOx.

Firing RFG will generally result in higher thermal NOx formation than firing natural gas due to the higher flame temperatures caused by higher hydrogen and olefin content in RFG. This is a consideration when establishing limits for units requiring combustion modification through application of NOx controls such as low-NOx burners (LNB) or Ultra-low NOx burners (ULNB). Depending on the volume of RFG generated at each facility, natural gas is often used as make-up fuel to the refinery fuel gas system which dilutes some of the hydrogen and olefin concentrations moderating the impact on NOx emissions.

Natural Gas

Natural gas used as a fuel source is generally referred to as "pipeline quality natural gas" and is composed of at least 70 percent methane by volume. Natural gas contains other light hydrocarbons such as ethane, propane, and butanes, but it is being "sweetened" or desulfurized before sending into a pipeline. Natural gas typically has a higher heating value (HHV) between 950 and 1,100 Btu per standard cubic feet and does not vary as much as refinery fuel gas.

Pressure Swing Adsorption Off-gas or Purge Gas

Pressure swing adsorption off-gas or purge gas (PSA off-gas) is a combustion fuel source used in SMR heaters that are equipped with a PSA system. PSA system separates and recovers high purity hydrogen as a continuous supply for use in refinery hydro-processing units. The remaining gas contains hydrogen, methane, and carbon dioxide which has heating value and is purged out of the PSA system and is routed to the burners of the SMR heater as a combustion fuel source.

Hydrogen Sulfide and Sulfur

Sulfuric acid manufacturing plants combust sulfur-bearing species to generate SO_2. The SO_2 then goes through a series of steps where it is converted into sulfuric acid. Hydrogen sulfide and sulfur does not serve as a fuel source per se, but since both provide heating value, they can act as combustion fuel sources. The greater the ratio of sulfur species are in the feedstock being sent to the furnace, the less the demand will be for supplemental fuel such as natural gas or refinery fuel gas.

NOx Control Principles

In the petroleum refining industry, there are five NOx control principles that control technologies or techniques rely on. These principles are listed in the table below and discussed in the subsequent sections.

Table A-1. NOx Control Principles

Principles	Description	Control Technologies
Reduce Peak Flame Temperature	Excess of fuel, air stream, or flue gas to reduce temperature in the combustion zone lowering thermal NOx formation	Low NOx Burners (LNB), Ultra Low NOx Burners (ULNB), Flue Gas Recirculation (FGR), Water or Steam Injection, Staged Air or Staged Fuel
Reduce Residence Time	Prevents formation of thermal NOx	Injecting Air, Fuel, or Steam
Chemical Reduction of NOx	Chemically reducing/removing oxygen from NOx to form N_2	Selective Catalytic Reduction, Selective Non-Catalytic Reduction
Oxidation of NOx with absorption	Convert NOx to N_2O_5 using, ozone, or H_2O_2 with subsequent scrubber	Injection of Oxidant and removal with wet scrubber (LoTOx™)
Removal of N_2 Species	Removal of N_2 as a reactant in the combustion process	Low Nitrogen fuel, Using Oxygen Instead of Air
Combination of Principles	Methods above can be combined to achieve higher NOx reduction	LNB/ULNB with SCR or LoTOx™

Reducing Peak Flame Temperature

The ideal stoichiometric air-fuel ratio of combustion produces higher flame temperatures that generate higher thermal NOx concentrations. By avoiding the ideal stoichiometric air-fuel ratio, combustion temperatures can be reduced, and thus reducing thermal NOx formation. Reducing the overall peak flame temperature involves cooling the primary combustion zone with an excess of fuel, air, flue gas, or steam. This principle prevents most of the nitrogen from ionizing which lowers the number of present reactants for the formation of NOx. This principle is typically employed by burner control technologies.

Reducing Residence Time

This technique is used in boiler LNB applications by rapidly mixing and restricting the flame to a short region where the combustion air converts to flue gas. This is immediately followed by injection of fuel, air, or recirculating flue gas. Similar to reducing peak flame temperature, the short residence time prevents the nitrogen from being ionized and reacting with the O_2.

Chemical Reduction of NOx

This technique uses a reducing agent such as ammonia or urea to remove oxygen from NOx to convert it to nitrogen and water. SCR and selective non-catalytic reduction (SNCR) use this principle to remove NOx from the flue gas. SCR is an effective technology most widely used in the refining industry and can be applied to nearly all refinery combustion sources in PR 1109.1.

Oxidation of NOx with absorption

This technique involves using either a catalyst, injecting hydrogen peroxide, or injecting ozone into the flue gas air flow and oxidizing the NOx where it is converted into water soluble N_2O_5. A scrubber is added to the process where N_2O_5 is absorbed into liquid phase resulting in a nitric acid solution that can either be neutralized prior to discharge or sold. LoTOx™ is a control technology that utilizes this principle and has been employed in FCCU refinery applications.

Removal of N_2 Species

This principle involves removing nitrogen by using oxygen instead of air in the combustion process. This technique is not commonly employed or practical for refinery applications.

Combination of Principles

Many of the listed principles can be combined to achieve a lower NOx concentration level than achievable levels by each single method. The maximum degree of NOx reduction is possible when principles are combined. For example, for the case of a refinery process heater, combining LNB/ULNB with post-combustion control such as SCR, can achieve 95% or greater NOx reduction if the controls are designed and engineered properly. Based on emissions data and equipment information, process heaters with combination of properly engineered NOx controls can achieve less than 2 ppmv NOx. However, available control technologies are limited when factors such as turndown ratio, stability of flame, availability or access to burners, and costs are taken into consideration.

NOx Control Technologies

This section outlines the control technologies that are commercially available and have been implemented throughout the refining industry or other industrial applications. The technologies are considered mature technologies if they have been in use for more than 30 years. With advances in computational fluid dynamics (CFD) and cold flow modeling, technology vendors have improved their understanding and have optimize their designs to function the greatest efficiency. Control technologies can be classified into two categories: combustion control and post-combustion control.

PR 1109.1 will focus on control technology options for the seven refinery source categories. Each source category has its unique challenges and implementation approach which will be discussed further in the section for each specific source category.

As part of the combustion control assessment, staff met with the three major burner manufacturers:

- John Zink Hamworthy Combustions
- Zeeco
- Callidus Technologies

All three process burner manufacturers have extensive experience in the refining sector along with a large process burner portfolio for various refinery applications. Their products can be found in many refinery related units within the South Coast Air District and throughout the world. Staff met with all three burner manufacturers to gather insight on the current state of process burner technology and advancements. For SCR technology, staff met with the two major catalyst manufacturers and suppliers: Umicore and Cormetech, both companies are world leaders in SCR catalyst technology and provide catalyst to many industrial sectors including petroleum refining. In addition, staff also met with SCR system designer CECO Peerless. The company has over 30 years of experience and expertise in new SCR construction and retrofit. Their SCR systems are engineered for optimal performance that can reduce NOx emissions by up to 95%.

Combustion Controls

Combustion controls are techniques that reduce NOx by modifying the combustion zone through installation of LNBs, ULNB, DLN or DLNE combustors, water or steam injection, and flue gas recirculation (FGR). Control techniques employ air staging or fuel staging techniques to maximize NOx reduction. This technique reduces the adiabatic peak flame temperature and is effective at reducing thermal NOx formation. Fuel NOx is not a concern in refinery combustion equipment since refinery fuel gas contains nearly zero nitrogen content. If combustion modification is not an option for reducing NOx emissions in certain refinery applications, such as the FCCU and petroleum coke calciner, post-combustion or flue gas treatment controls such as SCR, UltraCat™, or LoTOx™ can be used to reduce NOx in the flue gas stream. This section will also discuss several emerging combustion control technologies that have reached the commercial demonstration/licensing but are not commonly used. These emerging technologies have limited data available for source specific applicability. However, they show to be highly effective in reducing NOx emissions in their current stage of development.

BURNER CONTROL TECHNOLOGIES

Low NOx Burners and Ultra-low NOx Burners

There are several commercially available burner control technologies that can be applied to existing process heaters, boilers, or furnaces. Burners are typically classified based on their NOx emissions as: conventional, low-NOx (LNB), ultra-low NOx (ULNB), and next-generation ultra-low NOx burners. However, there is no industry standard or clear definition of what constitutes a LNB or ULNB. According to staff's recent discussions with John Zink Hamworthy Combustions, ULNB can be any LNB that utilizes internal flue gas recirculation or other advanced techniques to control the flame temperature that minimizes NOx generation. Process burners are typically custom designed for each application and several factors must be considered prior to selecting a burner. Replacing conventional burners with LNB or ULNB often requires special attention because of the flame dimensions and limited space within a refinery process heater.

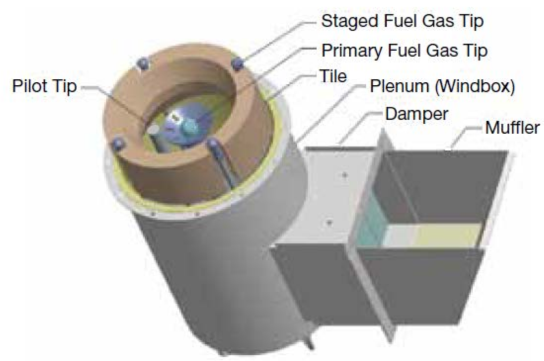


Figure A-1. Low NOx Burner Design

The American Petroleum Institute (API) 560 and 535, provides guidelines for the fired heaters and burners used for general refinery service. Recommended guidelines establish minimum requirements such as burner spacing, mechanical design, and higher heat density for optimal operation. Some manufacturers will guarantee ULNB performance to be <15 ppmv NOx from firing refinery fuel gas, however compliance tests for recent installations show that ULNBs operate at <25 ppmv. Burner performance is dependent on multiple factors, including burner orientation and arrangement, firebox size, heater type (force or natural draft), and fuel type. Using burners such as LNB or ULNB does not guarantee the NOx levels guaranteed by manufacturers. NOx emissions from burner will vary in real world applications due to specifics of the heater. Newer burner control technology (e.g., staged fuel burner, staged air burner, flue gas recirculation burner) will typically performs better than conventional burners (e.g., premix burner, raw gas burner).

It is important to note that in the South Coast Air District, most refinery process heaters have been retrofitted with first generation LNB or ULNB within the last 35 years under the RECLAIM program and they typically achieve NOx emission levels between 30 and 60 ppmv. Burner technology advancements make them good candidates for upgrades or retrofits to newer generation burners.

Dry Low-NOx (DLN) or Lean Premix Emission Combustors (DLE Combustors)

Prior to combustion, gaseous fuel and compressed air are pre-mixed, minimizing localized hot spots that produce elevated combustion temperatures and therefore, less NOx is formed. Atmospheric nitrogen from the combustion air is mixed with air upstream of the combustor at deliberately fuel-lean conditions. Approximately twice as much air is supplied as is needed to burn the fuel. This excess air is a key to limiting NOx formation, since very lean conditions cannot produce the high temperatures that create thermal NOx. Using this technology, NOx emissions have been demonstrated at single digits (< 9 ppmv at 15% oxygen on a dry basis) without further controls. The technology is engineered into the combustor that becomes an intrinsic part of the turbine design. Fuel staging or air staging is utilized to keep the flame within its operating boundaries. DLN is not available as a "retrofit" technology and must be designed for each turbine application. Post-combustion control such as SCR and the most effective and cost-effective option for NOx control in gas turbines

In gas turbine applications, DLN/DLE combustion is based on a concept of lean premixed combustion in which fuel is premixed with atmospheric nitrogen (from the combustion air) at the air-to-fuel ratio two times higher than the ideal stoichiometric level. Premixing gaseous fuel with combustion air before entering the combustor reduces peak flame temperature in the combustion zone, limiting thermal NOx formation. This lean premixed combustion process has now become the standard technique employed by gas turbine original equipment manufacturers (OEMs), particularly for natural gas and is referred to by a variety of trade names such as DLN (General Electric and Siemens-Westinghouse), DLE (Rolls-Royce), or SoLoNOx™ process (Solar® Turbines).

The premixing chamber must be specifically designed for every turbine and integrated into the turbine engine. Every four to five years, the combustion liners of the DLN/DLE combustors are deteriorated and must be replaced. When firing natural gas, most of the commercially available systems would guarantee a level of 9–25 ppmv NOx, dry range, depending on the manufacturer, turbine model, and application. Gas turbines fired with refinery gas typically have at least 10 percent greater amount of NOx emissions that natural gas fired turbines.

Water or Steam Injection

Water injection (WI) or steam injection (SI) is commonly used in the conventional gas turbine to quench the temperature down and reduces NOx to approximately 25 ppmv at 15 percent O_2, when operating on natural gas in 50–100 percent load range. Water injection provides greater NOx reduction than steam injection and corresponds to an approximate 70 to 80 percent reduction from uncontrolled levels for utility and large turbines operating on natural gas. However, water injection tends to increase carbon monoxide (CO) emissions considerably Application of water or steam injection in turbines has increased maintenance requirements due to erosion and wear. High purity water is used to minimize wear and fouling on turbine components (nozzles, combustor cans, turbine blades).

Great Southern Flameless Heater

Great Southern Flameless (GSF) Group developed a flameless furnace technology which accommodates all the required operational variances in a refinery heater while providing NOx emissions levels similar to that of an SCR. Because refinery heaters do not always operate at steady state, numerous design features were addressed in the GSF's flameless heater technology named "Flameless Nozzles Grouping (FNG)." Key features include:

- SCR level NOx emissions without traditional combustion with an SCR. Based on the GSF vendors, between 4 and 8 ppmv NOx can be achieved on refinery fuel gas;
- No flame or gas impingement due to patented castable refractory dimple pattern pins rotating flue gas to the wall;
- No hazardous by-products or ammonia slip and improved reliability; and
- Easy scale-up available to any required process heater size.

FNG is a technology that requires heater replacement and retrofit options are currently under development. Flameless combustion technology was applied for the first time to process heaters at Coffeyville refinery in Kansas (capacity: ~3,500 barrels per day (bpd)) in 2013. There is no current data available for large refinery applications (e.g., greater than 90,000 bpd).

ClearSign Core™ Burner

ClearSign Combustion Corporation has developed DUPLEX™ Technology, a new technology for reducing NOx emissions from fired heaters and boilers. The DUPLEX™ technology involves the installation of a porous ceramic surface where combustion is sustained. The combustion occurs inside the pores of this ceramic tile, resulting in reduced flame height and improved heat radiation. The premixing of air, fuel, and entrained flue gas prior to combustion at the duplex ceramic surface allows the combustion to occur at lower temperatures and lower reaction time which reduces thermal NOx formation. The combustion is contained within the porous ceramic surface, thus minimizing tube damage that can result from flame impingement. Flame impingement is one of the safety concerns that were raised by refinery stakeholders as the reason why traditional ULNB may not be an option. The ceramic surface also increases the overall heater efficiency due to improved radiation properties of the DUPLEX™ surface when compared to traditional ULNB.

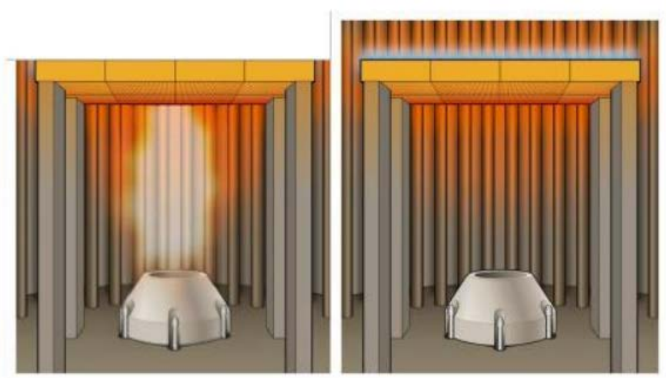


Figure A-2. Conventional burner heating up a DUPLEX tile

ClearSign Core™ process burners are the latest advancement and redesign of the DUPLEX™ technology. The redesigned ClearSign Core introduces a new pilot which simplifies the structure and operation of the burner. Adding the pilot eliminated the need of a transition burner which improves stability, turndown, and size making the redesigned core a direct replacement for traditional ULNB. The flame is compact and less sensitive to heat density and burner spacing limitations commonly encountered with traditional ULNB offerings. This is ideal for existing process heaters where current generation ultra-low NOx burners are not suitable due to the arrangement of the burner and combustion surfaces. Conventional ULNBs typically operate 15 to 40 ppmv under ideal conditions and can be as high as 50 ppmv in some cases where burner spacing is not optimal. ULNBs encounter flame shape issues whereas the ClearSign™ core technology has the capability to achieve sub-5 ppmv NOx corrected to 3% O_2. The core technology is capable of a 5:1 turndown ratio and achieve sub-30 ppmv CO throughout the turndown. In addition, the technology does not have tip plugging or fouling issues commonly associated with traditional ULNB.

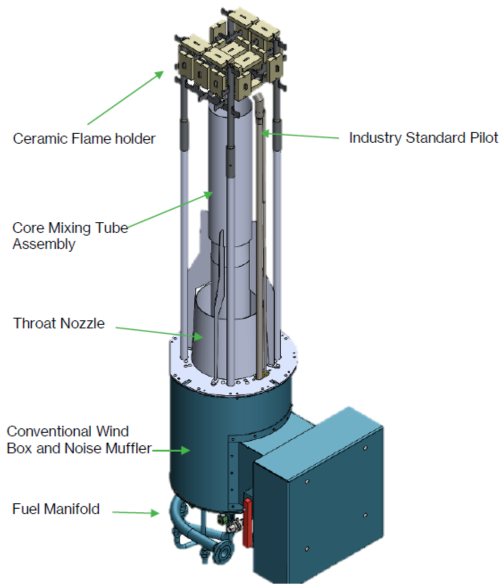


Figure A-3. ClearSign Core Process Burner

There is currently a demonstration project of the ClearSign Core™ process burner within the District located at World Oil. The BACT demonstration project is conducted in partnership with ClearSign, World Oil, and South Coast AQMD to demonstrate the capabilities of these latest generation ClearSign burners. As of March 2021, the ClearSign Core™ burners have been installed and operating in a five burner, 39 MMBtu/hr vertical cylindrical heater. Near full firing rate has been achieved with all 5 burners operating. Field installations of the technology so far have demonstrated safe, reliable performance with NOx levels at 29.3 ppmv corrected to 3 percent oxygen. Burners are currently operating with some modifications resulting in higher than expected NOx performance. The replacement components are being fabricated for installation in 2022. Once the replacement components are installed, ClearSign anticipates sub-5 ppmv performance on natural gas.

On August 12, 2020, ClearSign announced their partnership with Zeeco, a worldwide leader in design and manufacturer of advanced combustion controls. The agreement will increase manufacturing, product development, and performance testing of the ClearSign technology which has the potential for widespread use by refiners and other users. The technology has been installed many locations and applications such as once-through-steam-generators, process heaters, and flares and has demonstrated low NOx emissions levels in stable, safe operation with firing rates ranging from 6 to 60 MMBtu/hr.

John Zink Hamworthy SOLEX™ Burner[1]

John Zink Hamworthy presented information regarding the SOLEX™ technology at Working Group Meeting #9 on December 12,2019. SOLEX™ is a next generation ULNB technology that is currently in development which can achieve 5 ppmv NOx emissions regardless of fuel composition and furnace temperature, making this ideal for applications using refinery fuel gas. The composition and higher heating value (HHV) of refinery fuel gas can vary, potentially lead to higher NOx emissions. The burner is designed with two significant combustion zones to achieve this emissions level from startup to full capacity with near-zero CO emissions. In addition, the SOLEX™ burner's compact flame lengths solve many issues ultra-low NOx burner technologies face in the market today such a long flame that can lead to flame impingement of process tubes. Achieving 5 ppmv NOx emissions has traditionally required flue gas treatment solutions such as Selective Catalytic Reduction (SCR) systems. The SOLEX™ burner delivers similar NOx emissions and performance using proven combustion method and is capable of being wall, floor, or roof mounted making in applicable in various heater types. The performance for each of the categories are summarized here:

- NOx emissions
  - Can replace the need for SCR or other NOx reducing technology
  - Independent of fuel compositions >75% H_2, air preheat, furnace temperature, operation range, and firebox heat density
  - High predictability and repeatability
- CO emissions
  - Decoupled from cold furnace temperatures
  - Near-zero CO emissions at startup and turndown conditions
- Flame
  - Lengths less than half of ultra-low NOx staged fuel burners
  - Solution for tight burner spacing arrangements
  - Round or flat flame options
- Retrofits
  - Fits traditional ultra-low NOx burner footprints
  - Up-fired, down-fired, and horizontally fired

To achieve the performance, the SOLEX™ burners requires advanced combustion control scheme along with a forced and an induced draft fan. John Zink is currently working on a commercial demonstration of the SOLEX™ burner with a facility within the District.

[1] John Zink Hamworthy SOLEX Burner at https://www.johnzinkhamworthy.com/wp-content/uploads/solex-burner.pdf. Accessed on July 10, 2020.

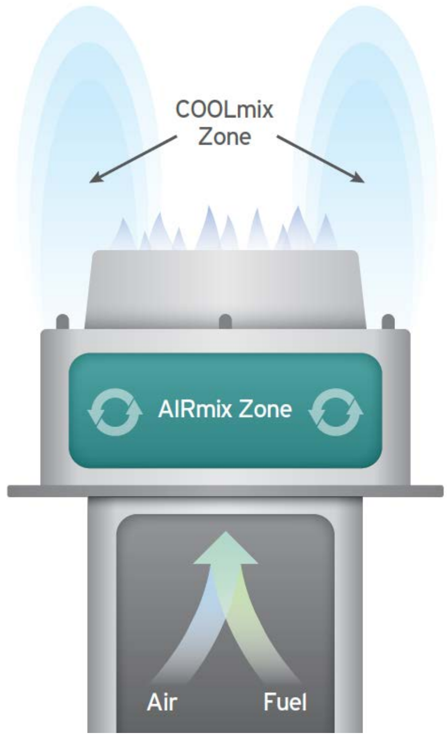


Figure A-4. John Zink SOLEX™ Burner

FLUE GAS TREATMENT TECHNIQUES

Selective Catalytic Reduction

SCR technology is a well-established and mature technology for controlling NOx emissions. SCR is a chemical process of using a reductant like ammonia (NH_3) to convert NOx in the flue gas into nitrogen (N_2) and water (H_2O) with the aid of a catalyst.

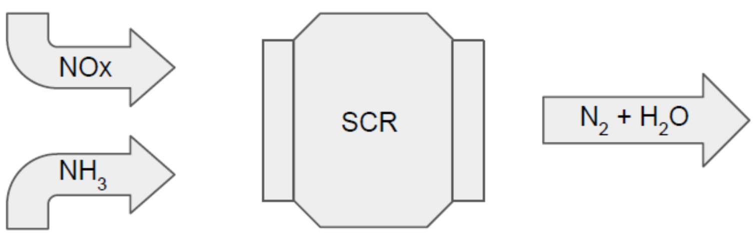


Figure A-5. NOx Reductions in SCR

Over the past three decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available and can reduce up to 95 percent NOx emissions through the following reactions:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$ (Reaction 1)
$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$ (Reaction 2)

It should be noted that, at temperature above 797°F, ammonia can be oxidized to form NO and N_2O which are undesirable reactions since NO and N_2O will ultimately convert to NOx and increase the NOx emissions.

$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$ (Reaction 3)
$4NH_3 + 4NO + 3O_2 \rightarrow 4N_2O + 6H_2O$ (Reaction 4)

A successful SCR catalyst can facilitate the reduction of ammonia (Reactions 1 and 2) while subsiding the ammonia oxidation reactions (Reactions 3 and 4). Typically, the SCR catalysts are vanadium, titanium, and/or zeolite based, with different sizes, shapes, and operating temperatures. New generation of low temperature SCR catalyst can achieve 90 percent NOx reduction at temperatures lower than traditional catalyst. For example, Umicore's low-temperature catalyst, TripleCat DNX-LT (Figure 1) can achieve greater than 90 percent NOx reduction for the flue gas between 400° and 500°F.

Conventional SCR catalysts: 500°–800°F
Low temperature SCR catalysts: 300°–500°F
High temperature SCR catalysts: 800°–1,100°F

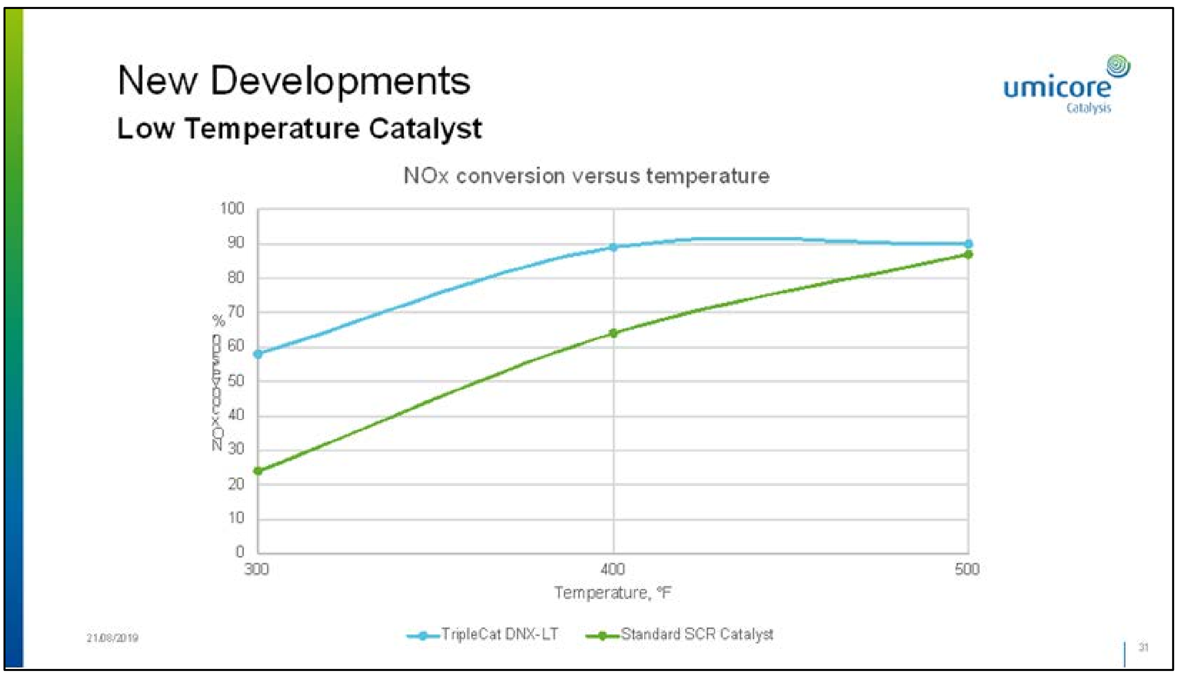


Figure A-6. Umicore's TripleCat DNX-LT

The stoichiometric amount of ammonia required is one mole of ammonia per mole of NOx reduced (NH_3/NOx = 1). Ammonia injection and mixing is critical since a non-uniform distribution and mixing can result in inadequate NOx reductions and/or lead to increased ammonia emissions (ammonia slip). Ammonia has the potential to form secondary pollutants (e.g., PM) in the atmosphere, especially if there are high concentrations of sulfur in the flue gas. To reduce the ammonia slip caused by imperfect ammonia distribution and mixing, SCR catalyst manufacturers have developed an ammonia slip catalyst, a layer of catalyst installed downstream of the SCR catalyst. Early generation of ammonia slip catalyst were based on precious metal which is highly active for ammonia oxidation. The new generation of ammonia slip catalyst offers the following advantages:

- Enhancing the selective reduction of NO to N_2 and supporting the oxidation of CO to CO_2 while suppressing the oxidation of ammonia to NOx;
- Allowing for operations at higher ammonia to NOx ratios to ensure complete NOx conversion;
- Maintaining low ammonia slips; and
- Reducing the overall SCR catalyst volume while maintaining the high NOx control efficiency.

However, SCR system designers and catalyst manufacturers will generally prefer to optimize the ammonia injection and distribution before recommending an ammonia slip catalyst, since the additional catalyst adds to the cost and requires additional space. Over the years, SCR system designers and catalyst manufacturers have enhanced their understanding of mixing and distribution of ammonia to achieve higher NOx removal efficiencies. Computational fluid dynamic modeling and cold flow modeling are utilized to help achieve uniform ammonia to NOx distribution and mixing in the SCR design phase to optimize SCR configuration and alleviate the need for an ammonia slip catalyst.

The South Coast AQMD requires the use of aqueous ammonia instead of anhydrous ammonia for SCRs due to safety concerns. In general, aqueous ammonia has lower risks and higher operating costs than anhydrous ammonia. A larger volume of aqueous ammonia is required to achieve the same NOx reduction, which increases delivery costs (e.g., delivering 29 percent aqueous ammonia includes the delivery costs of transporting the remaining 71 percent water). Aqueous ammonia also requires either compressed air for atomization or vaporizers to evaporate the water. The costs for operating with aqueous ammonia are approximately two times higher than the costs for operating with anhydrous ammonia.

LoTOx™ Application with Scrubber

LoTOx™ stands for "Low Temperature Oxidation" process where ozone is injected into the flue gas stream to oxidize insoluble NOx compounds into soluble NOx compounds. These soluble compounds can then be removed by various neutralization reagents (caustic solution, lime, or limestone) as well as the BELCO® regenerative LABSORB™ process.[2] LoTOx™ is a low temperature operating system in a range of 140°–325°F, while the optimal temperature is generally less than 300°F. The LoTOx™ is a registered trademark of Linde LLC (previously BOC Gases) and was later licensed to BELCO® of DuPont for refinery applications. An arrangement of LoTOx™ with EDV® scrubber is shown in Figure 2.

A typical combustion process produces about 95 percent NO and 5 percent NO_2. Both NO and NO_2 are relatively insoluble in aqueous solution, and thus a wet gas scrubber is inefficient in removing these insoluble compounds from the flue gas stream. However, with the injection of ozone into the flue gas stream, NO and NO_2 can be easily oxidized to highly soluble compounds (N_2O_5) (Reactions 5 and 6) and subsequently converted to nitric acid (HNO_3) in the wet scrubber (Reaction 7). The nitric acid is readily absorbed in aqueous scrubbing solution (Reaction 8) or by

[2] Edwin H. Weaver, Wet Scrubbing System Control Technology for Refineries - An Evaluation of Regenerative and Non-Regenerative Systems, Belco Technologies Corporation, Presented at the Refining China 2006 Conference, April 24-26, 2006, Beijing, China.

dry/semi-dry scrubber adsorbents such as limestone or lime (Reactions 9 and 10) and is removed from the wet scrubbers. In addition, ozone is highly selective for NOx relative to other combustion products such as SO_2 and CO and the rate of oxidizing reactions for NOx (Reactions 5 and 6) are faster compared to CO or SO_2 oxidation reaction (Reactions 11 and 12), and thus, the presence of SO_2 or CO does not impact NOx removal.

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 – Fast)
$2NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2HNO_3$	(Reaction 7 – Very Fast)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO_3 + CaCO_3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO_3 + CaOH \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 – Very Slow)
$CO + O_3 \rightarrow CO_2 + O_2$	(Reaction 12 – Slow)

The LoTOx™ process requires oxygen supply for ozone generation. Unlike SCR technology which requires ammonia storage, the LoTOx™ technology modulates ozone generation on demand as required by the process. A ratio of NOx/O_3 of about 1.75–2.5 is needed to achieve 90–95% NOx conversion and reduction. The ozone that does not react with NOx in the LoTOx™ process is scavenged by sulfite in the scrubber solution and the ozone slip is in a range of zero to 3 ppmv.

Some advantages of LoTOx™ application in comparison to SCR are as follow:

- LoTOx™ does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases.
- LoTOx™ can be integrally connected to a wet (or semi-wet) scrubber and become a multi-component air pollution control system that can reduce NOx, SOx, and PM in one system whereas SCR is primarily designed to reduce only NOx.
- There is no ammonia slip, SO_3, and ammonium bisulfate issue associated with LoTOx™ application.

Potential drawbacks with LoTOx™ include:

- Significant amount of water is needed for the process, and it consequently generates waste effluent that requires an effluent treatment system. Thus, a water supply and effluent treatment system will need to be constructed to accommodate the LoTOx™ system.
- Since the LoTOx™ system requires high electrical power usage and oxygen demand, annual operating costs for the ozone generator could be potentially high.
- Nitrates in wastewater effluent may be a concern for treatment and/or discharge of the wastewater.

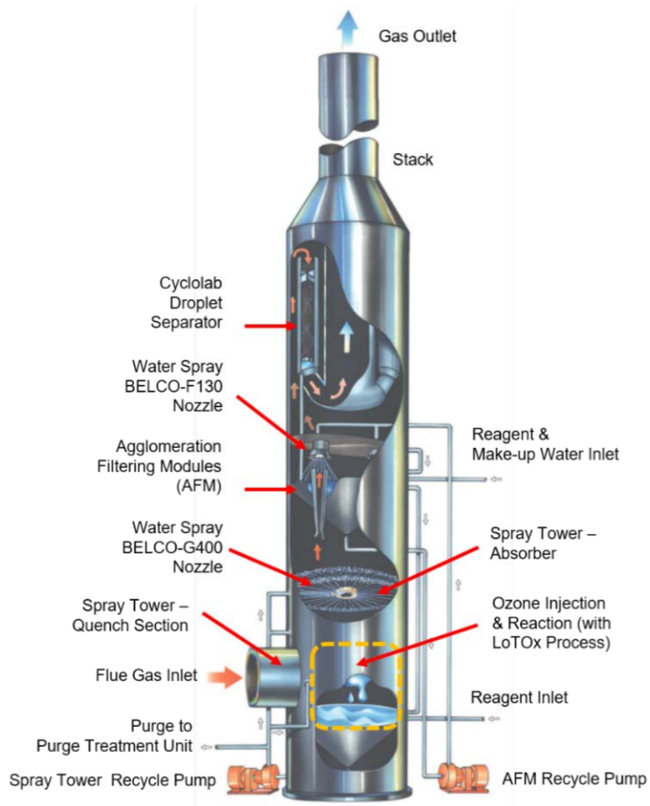


Figure A-7. EDV® Scrubber with LoTOx™ NOx Control[3]

There are more than fifty LoTOx™ systems installed for FCCUs, boilers, furnaces, and other combustion equipment since 1997, and more than two dozen applications with DuPont Clean Technologies' ("DuPont") BELCO® EDV® scrubbers since 2007. The table below contains a list of the LoTOx™ applications at refineries. The EDV® scrubber with LoTOx™ system has been in operation since February 2007 at a 52,000 barrels per day FCCU at Tesoro's Texas City Refinery and at a 12,500 barrels per day FCCU at HollyFrontier's Cheyenne Refinery in Wyoming since September 2015. Applications in FCCU in refineries met 8–20 ppmv NOx. According to the manufacturers[4], LoTOx™ can be designed to achieve 2 ppmv NOx from current inlet concentrations (85–95 percent control efficiency) for FCCUs. The table below list existing LoTOx™ installations.

[3] BELCO® Wet Scrubbing Systems at https://www.dupont.com/content/dam/dupont/products-and-services/consulting-services-and-process-technologies/clean-technologies-and-technology-licensing/documents/DSP_%20BELCO_EDV_brochure_K24207.pdf. Accessed on September 5, 2019.

[4] Final Staff Report on Proposed Amendments to Regulation XX - NOx RECLAIM, South Coast AQMD December 4, 2015, page 60.

Table A-2. LoTOx™ Installations

No	Application	Exhaust Gas Flow (scfm)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1–5	Five FCCUs in the U.S.	40,000–260,000	70–120	8–20	80%	2007
6–7	Two sulfuric acid plants in the U.S.	16,800	90	10	90%	2008
8–18	Nine FCCUs and two LoTOx™ ready installation in the U.S.	12,000–310,000	30–250	10–18.5	93%	2008–2015
19–35	Ten FCCUs, a refinery boiler, six LoTOx™ ready installation in China	90,000–390,000	100–350	20–73	80%	2012–2015
36–37	FCCUs in Thailand & Romania	43,000–135,000	230–250	20–73	80%	2015–2019

UltraCat™ Application

UltraCat™ is a multi-component air pollution control technology developed by Tri-Mer. UltraCat™ ceramic catalyst filters are composed of ¾ inch thick fibrous ceramic tube walls embedded with proprietary catalysts throughout the wall. UltraCat™ can remove NOx, SO_2, PM, hydrogen chloride (HCl), dioxins, and metals such as hexavalent chromium and mercury. The ceramic filters are self-supporting meaning they do not require filter cages and are described as having a service life of five to ten years. SOx and acid gases are controlled via dry sorbent injection upstream of the ammonia injection. The optimal operating temperatures for PM and NOx control are approximately 300°F to 750°F. Aqueous ammonia injected upstream of the catalytic filters is used to remove NOx; removal efficiency is about 70 percent starting at 350°F and improves to over 90 percent between 400°F and 800°F. Less than 5 ppmv of ammonia slip can be achieved. A NOx removal efficiency of greater than 95 percent is achievable in certain applications. Dry sorbent such as hydrated lime (sodium bicarbonate) injected upstream of the catalytic filters is used to remove SO_2, HCl, and other acid gases with a removal efficiency of 90 to 98 percent. Particulate control is reported to a level of 0.001 grains/dcsf (2.0 mg/Nm^3) regardless of inlet loading. In addition, mercury control is also possible. UltraCat™ filters are arranged in a baghouse configuration with low pressure drop (about 5 inches water column), and it has a reverse pulse-jet cleaning action (the filters are back flushed with air and inert gas to dislodge the particulate deposited on the outside of the filter tubes). The UltraCat™ catalytic filtering system is depicted in the figure below.

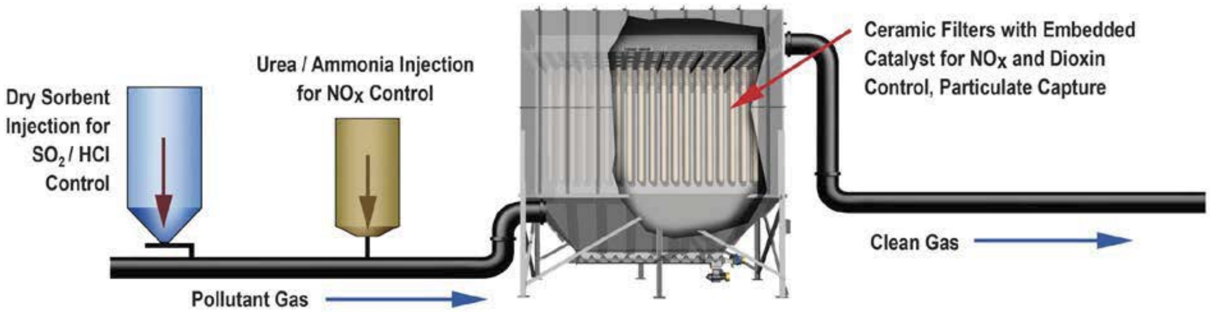


Figure A-8. UltraCat Filters

The technology is modular and will allow for a phased approach using 20 percent of the total flow as an opportunity to demonstrate actual capability of the technology. Tri-Mer stated that they can retrofit the currently existing baghouse to the UltraCat™ technology which will minimize downtime and space constraints of the facility.

APPENDIX B BOILERS AND PROCESS HEATERS

Process Heaters and Boilers

The largest category of equipment subject to PR 1109.1 is the boilers and process heaters category which represents the largest NOx emission sources at refineries and related industries. Over 60 percent of all emissions from equipment subject to PR 1109.1 is attributable to process heaters and boilers. Process heaters are indirect-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. Boilers are combustion sources used to generate the steam necessary for plant operations. Steam is primarily used for heating, separating hydrocarbon streams, hydrogen production, stripping medium, and producing electricity by expansion through a turbine. The design and arrangement of a fired process heater is different from that of a fired boiler, so the challenges associated with installing NOx controls may be different. For example, in a boiler, the number and size of a burner is different from that of a process heater, and it does not typically encounter the firebox size and spacing constraints like those found in some process heaters. However, boilers and process heaters are similar in that they are both combustion devices which burns fuel and most control technologies developed for controlling NOx emissions are applicable to both.

Due to the variety of boilers and process heaters, the units were segregated into six major subcategories prior to conducting the BARCT assessment as shown in the figure below.

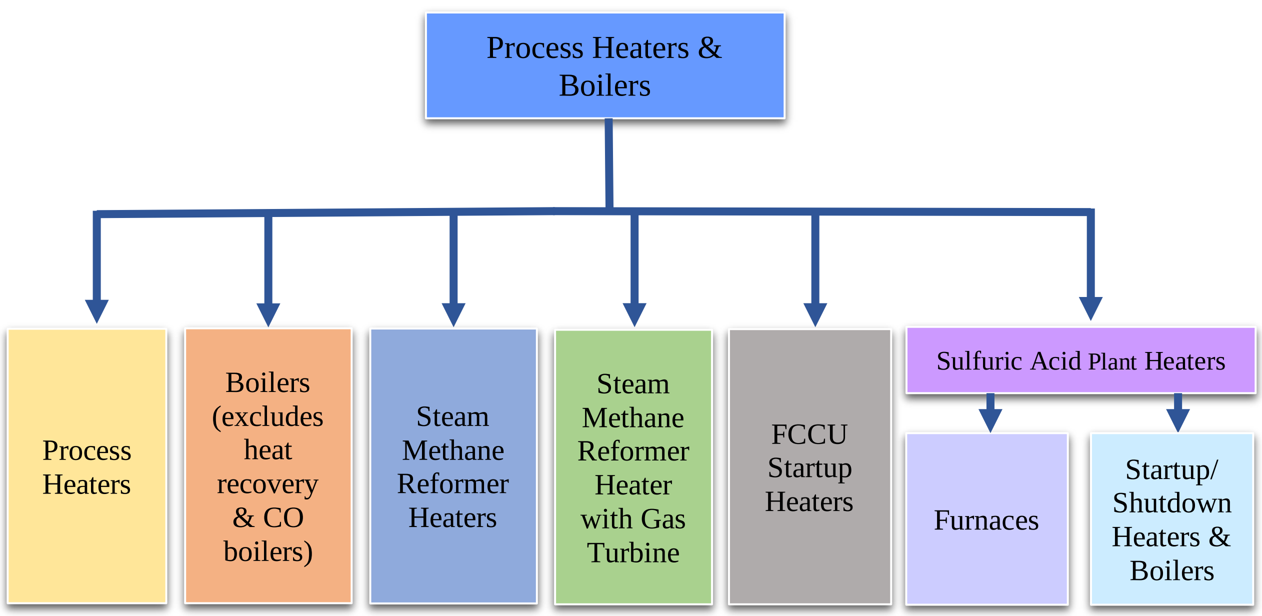


Figure B-1. Six major sub-categories of Boilers & Process Heaters Category

Each of the large boiler and process heater subcategories were divided into smaller categories based on size or maximum rated heat input in order to conduct a more granular BARCT assessment. Equipment was also grouped into subcategories to reflect the applicable technology control options. Staff divided the boilers and heaters into four categories as described in the table below.

Table B-1. Boiler and Heater Size Categories

Heaters and Boilers Size Categories
< 20 MMBtu/hr
≥20 to <40 MMBtu/hr
≥40 to ≤110 MMBtu/hr
>110 MMBtu/hr

Process Heaters

Process heaters are indirect-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. In a fired process heater, fuel and air are combusted in a firebox to produce heat that is transferred to process tubes containing process fluid. Process heaters are used in various processing units throughout the refining industry and have many applications – heaters are specialized based on their processing unit location and application. Examples of specialized applications include steam methane reformer (SMR) heaters located in hydrogen plants and sulfuric acid furnaces located in sulfuric acid plants, each are designed for different purposes, and each will combust different fuel types. The fuel burned in an SMR heater may be refinery gas, natural gas, pressure swing adsorption (PSA) off-gas or a combination of these fuels. The combustion fuel in a sulfuric acid furnace can consist of sulfur, natural gas, refinery gas, and hydrogen sulfide. The size and number of burners will also vary greatly. An SMR heater can potentially have over 350 small burners whereas a sulfuric acid furnace will have two large burners. Each burner type will have different design requirements for the intended application and different associated costs.

Boilers

Boilers are combustion sources used to generate the steam necessary for plant operations. A boiler converts water into steam through combusting and converting a fuel into heat which is transferred to the contained water and ultimately is converted to steam. Steam is an integral part of refinery or industrial operations and is primarily used for heating, separating hydrocarbon streams, hydrogen production, stripping medium, and produce electricity by expansion through a turbine.

There are two main categories of boilers:

- Fire Tube Boilers – consist of a system of tubes through which the heat source passes. The tube containing the heat source is surrounded by water which gets heated as the tube temperature rises. Eventually, the water is converted to steam and gets released.
- Water Tube Boilers – in contrast to fire tube boilers, these boilers consist of a series of water-containing tubes surrounded and heated by hot combustion gases. This is the most common type of large boilers found in refinery applications because very high pressures can be obtained.

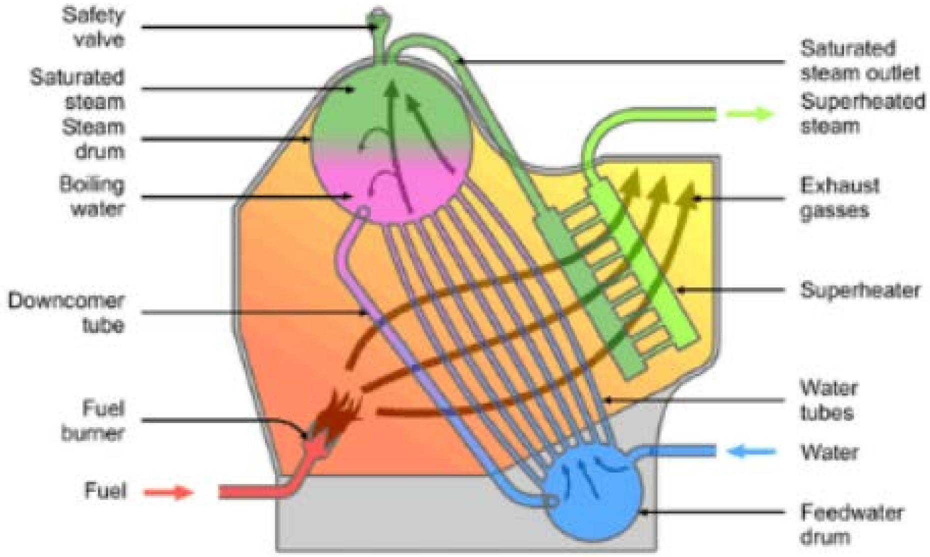


Figure B-2. Water Tube Boiler

Two other types of boilers used for steam generation are heat recovery boilers and carbon monoxide (CO) boilers. Heat recovery boilers are excluded from the boiler category since they are unfired units that do not generate any NOx emissions. There is one CO boiler located in the South Coast Air District which is currently unfired and operated as a heat recovery device used for steam generation. However, the CO boiler is equipped with LNB and capable of firing. If the CO boiler fires and becomes a combustion source, the emissions will be aggregated with the emissions from the FCC unit and will be subject to the NOx limit for the FCCU category.

The other type of unfired heat recovery boilers is used in the exhaust section of a gas turbine and commonly known as a heat recovery steam generator (HRSG). These types of boilers recover heat from the exhaust of a gas turbine to produce low, medium, and high-pressure steam. Another category of unfired boilers is waste heat boilers which similarly recover heat from process flue gas streams to generate steam. These types of units are generally located downstream of furnaces or heaters and can be found throughout the facilities such as coke calciner, sulfuric acid plants, hydrogen production plants and sulfur recovery plants. These types of unfired units have no combustion source and hence no NOx emissions.

Steam Methane Reformer Heaters

Steam methane reformers are specialized process heaters used in hydrogen production. SMR heaters burn fuel (PSA off-gas, natural gas, or refinery gas) to generate heat for the endothermic reforming reaction of hydrocarbon and steam over a nickel-based catalyst. As a result, SMR heaters typically operate at a higher temperature than traditional process heaters (2,100 °F) which has the potential for higher NOx emissions. The burner arrangement is also unique in SMR heaters. They can be either down-fired or side-fired and the number of burners can be over 350 burners in some cases.

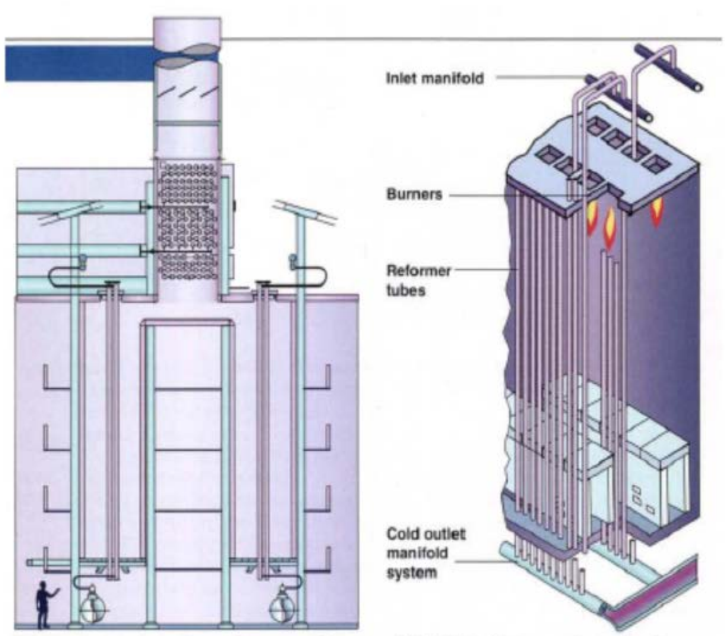


Figure B-3. Typical reformer heater designs can potentially have over 300 burners. All are greater than 110 MMBtu/hr in size

Steam Methane Reformer Heater with Integrated Gas Turbine

There is a special case arrangement where an SMR heater is integrated with a gas turbine. There is one refinery subject to PR 1109.1 where this arrangement exists and therefore, this unit has been segregated into its own subcategory. In a typical gas turbine, natural gas is fired in the gas turbine and the hot exhaust stream is normally sent to a HRSG, where the heat is recovered to generate steam – this is known as combined cycle operation. However, when an SMR heater is integrated with a gas turbine, part of the hot exhaust stream from the gas turbine replaces the furnace combustion air which increases thermal efficiency. This provides preheated air into the furnace, thus reducing the fuel demand to the SMR heater. This is typically referred to as integrated operation. For this arrangement, only a portion of the gas turbine exhaust is used as heater combustion air. The remaining gas turbine exhaust combines with the SMR heater exhaust prior to exiting the stack, as a result, the NOx emission is corrected to 15% and not 3% oxygen like a typical SMR heater. The SMR heater in this special arrangement is equipped with combination of NOx controls, LNB and SCR, which allows the unit to perform at less than 5 ppmv NOx at 15% oxygen.

FCCU Startup Heaters

Startup heaters or direct-fired air heaters are typically used in Fluidized Catalytic Cracking Units (FCCU) in petroleum refineries. These types of heaters are primarily used during startup operations to heat the catalyst bed in the regenerator section of the FCCU. Once the catalyst bed is heated up to the desired temperature or during normal operation, the heater is not fired and air flows directly through the regenerator through the air heater without being heated. These heaters are not often used – some are only used once every five years.

Sulfuric Acid Plant Startup Heaters and Boilers

There are two startup heaters and one start-up boiler located at sulfuric acid plants which are used as part of the startup cycle. The heaters are used for pre-heating the furnace and converter catalyst during cold startups after an extended maintenance outage. One facility has a startup boiler that provides steam when the main furnace is down – steam for the plant is primarily generated from the waste heat recovery boiler after the furnace.

Sulfuric Acid Furnaces

Sulfuric acid furnaces are another specialized subcategory of heaters that are utilized at sulfuric acid plants to produce sulfur dioxide gas which ultimately is converted into sulfuric acid. There are two sulfuric acid furnaces in PR 1109.1, and both are spent acid regeneration furnaces. These types of furnaces are primarily used for decomposition of spent sulfuric acid generated from the refinery's alkylation process. Feedstock or raw materials are from a variety of sulfur-containing streams and are fed into the furnace's combustion chamber. Depending on facility location, raw materials may include spent acid, hydrogen sulfide, liquid sulfur and hydrocarbon at various ratios. Hydrogen sulfide and sulfur both provide heating value when used as raw materials, however hydrogen sulfide has a much higher combustion heat than sulfur. This difference in the ratio of sulfur or hydrogen sulfide to spent acid affects fuel demand and NOx produced in the regeneration furnace.

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

As part of the BARCT assessment, staff reviewed existing South Coast AQMD regulatory requirements that affect NOx emissions for combustion equipment at petroleum refineries and facilities with related operations. The combustion equipment within the refining sector consists of seven main source categories. Staff evaluated NOx limits currently achieved in non-refinery settings for the purpose of technology transfer, source specific regulations, and regulations affecting specific equipment (e.g., boilers and heaters). NOx emissions from boilers and heaters are regulated under several rules, including Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters; and Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (Regulation XX). The previously applicable NOx system-wide standards are listed in the following tables. Table B-1 summarizes regulatory NOx limits for the existing non-refinery boilers and heaters in the South Coast AQMD and Table B-2 lists the RECLAIM BARCT limits for refinery and non-refinery sector heaters and boilers. The RECLAIM BARCT limits established are not actual limits imposed one each individual unit, but an assumption of what of what each unit can do to meet the shave targets, thus actual limits that the unit may have to meet be higher than the BARCT limits determined in the assessment. RECLAIM offered facilities the flexibility to use RTCs from overcontrolling another unit or shutting down equipment.

Table B-2. South Coast AQMD NOx Rules and Limits for Heaters and Boilers

Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters	
Equipment Size	NOx Limit
>75 MMBtu/hr	5 ppmv
>25 but <75 MMBtu/hr	9 ppmv

Table B-3. South Coast AQMD RECLAIM NOx Assessments for Heaters and Boilers

Refinery Sector Limits and Assessments		
	2005 RECLAIM BARCT	**2015 RECLAIM BARCT**
Boilers and Heaters: <20 MMBtu/hr	12 ppmv	N/A
Boilers and Heaters: ≥20–<40 MMBtu/hr	9 ppmv	N/A
Boilers and Heaters: ≥40–≤110 MMBtu/hr	25 ppmv	2 ppmv at 3% O_2
Boilers and Heaters: > 110 MMBtu/hr	5 ppmv	
Non-Refinery Sector Limits and Assessments		
	2005 RECLAIM BARCT	**2015 RECLAIM BARCT**
Utility Boilers at Electric Power Generating Systems	7 ppmv	
Boilers	9–12 ppmv	No new BARCT
Heaters	60 ppmv	No new BARCT
Heat Treating Furnaces: > 150 MMBtu/hr	45 ppmv	9 ppmv at 3% O_2
Glass Melting Furnaces	1.2 lb/ton	80% reduction

Assessment of Other Regulatory Requirements

Regulatory requirements of South Coast AQMD and other air districts are compared to ensure that proposed limits under PR 1109.1 are not less stringent and to evaluate the current performance of similar units in similar industries. Other air districts' NOx rules and limits for heaters and boilers are shown in the following tables.

Table B-4. Bay Area Air Quality Management District

Bay Area Air Quality Management District	
Regulation 9-10-301	
Description	NOx Limit – Operating Day (ppmv*)
Refinery-Wide NOx limit for boilers, steam generators and process heaters, excluding CO Boilers	30

*Converted from lb/MMBtu

Table B-5. San Joaquin Valley APCD

Rule 4306 Boiler, Steam Generators, and Process Heaters – Phase 3				
Refinery Units (MMBtu/hr)	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit (ppmv)	CO Limit (ppmv)	NOx Limit (ppmv)	CO Limit (ppmv)
5 to 65	30	400	40	400
65 to 110	25	400	40	400
>110	5	400	40	400

Assessment of Emission Limits of Existing Units

Most units within the process heaters and boilers category are currently regulated under RECLAIM and most units rated greater than 40 MMBtu/hr do not have any existing NOx permit limit. In contrast, most units rated less than 40 MMBtu/hr have NOx permit limits. Permit limits, source test data, and emissions data submitted to staff in the facility confidential surveys were analyzed to identify the emission levels being achieved with existing technology. Current and emerging technologies are assessed to determine the feasibility of achieving lower NOx emission levels. An initial BARCT emission limit is proposed based on the BARCT assessment. Costs are gathered and analyzed to determine the cost for a unit to meet the proposed initial NOx emission limit. Cost-effectiveness calculation considers the cost to meet the initial proposed NOx limit and the reductions that would occur from implementing a technology that could meet the proposed limit. A final BARCT emission limit is established based on the BARCT assessment, including the cost-effectiveness and incremental cost-effectiveness analysis.

Process Heaters

There is a total of 139 units in the process heater category and most units less than 40 MMBtu/hr currently have a NOx permit limit that ranges from 15 to 45 ppmv. Units larger than or equal to 40 MMBtu/hr typically do not have a permit limit, however units that have a NOx permit limit range from 5 to 9 ppmv. These lower NOx concentrations are usually achieved with the operation of post-combustion controls such as SCRs.

Boilers

There is a total of 28 boilers in this category. Most units less than 40 MMBtu/hr currently have a NOx permit limit ranging from 9 ppmv to 40 ppmv and are fueled by natural gas. Over half of the units larger than or equal to 40 MMBtu/hr, do not have a permit limit and no NOx control. Only 8 units currently have SCRs installed and their NOx permit limits range from 9 to 17 ppmv NOx.

Steam Methane Reformer Heaters

All 11 SMR heaters in PR1109.1 are large heaters that range in size from 146 to 931 MMBtu/hr for this subcategory. There is one special case located at one refinery where the SMR heater shares a combined stack with an auxiliary boiler. The boiler provides steam for the reforming process, but the SMR heater has a slightly higher firing duty than the boiler (145.97 MMBtu/hr vs. 139.5 MMBtu/hr). The SMR heater has a higher NOx potential so this special unit with a combine stack will qualify for the conditional limit of 7.5 ppmv – this unit is currently performing at 7.2 ppmv. Most of the SMR heaters in this category are currently equipped with NOx emissions control such as LNB and SCR – majority are performing at 5 ppmv or less at 3% oxygen.

Steam Methane Reformer Heaters with Gas Turbine

There is one refinery that operates an SMR heater with an integrated gas turbine and will be categorized as its own sub-category. The arrangement and operation are unique when compared to other SMR heaters. The SMR is equipped with LNB and SCR and currently meeting the proposed BARCT of 5 ppmv at 15% oxygen.

Startup Heaters

There are five heaters in this category and annual emissions from this category is 0.0029 tons per day based on 2017 annual emissions data. NOx controls for this category of heaters are not cost-effective at $1.7 MM per ton of NOx reduced and will have a low-use exemption. The startup heaters are associated with the FCCUs and only used during FCCU startups.

Sulfuric Acid Furnace

There are two furnaces in the category, and both have a heat input greater than 40 MMBtu/hr. Both furnaces operate below 30 ppmv NOx.

Startup Heaters and Boilers at Sulfuric Acid Plants

Each of the two Sulfuric acid plants have startup heaters. The startup heaters are used to heat up the catalytic converter during periods of unit startup. Only one facility has a startup boiler that is only operated when the facility is down for maintenance.

Table B-6. Emissions of Existing Units

Units	Size (MMBtu/hr)	Total 2017 NOx Emissions (tpd)	NOx in Exhaust Flue Gas @ 3% O_2 (ppmv)
Process Heaters	**5.5 to 550**	**5.06**	**1.7 to 134**
Boilers	**14.7 to 352**	**2.56**	**4.5 to 117**
SMR Heaters	**146 to 785**	**1.02**	**1.5 to 66**
SMR Heater with Gas Turbine	**316 to 931**	**0.08**	**4.4[(1)]**
Startup Heater	**26 to 165**	**0.003**	**11.2**
Sulfuric Acid Furnace	**73.6 to 150**	**0.10**	**23 to 28**
Startup Heaters and Boilers at Sulfuric Acid Plants	**15 to 50**	**0.001**	**29 to 94**

(1) Corrected to 15 percent oxygen

Assessment of Pollution Control Technologies

As part of the BARCT assessment, staff conducted a technology assessment to evaluate available NOx pollution control technologies for all categories. Staff reviewed facility provided survey data, CEMS data, scientific literature, vendor information, and strategies utilized in practice. Staff also met with technology manufacturers to evaluate the technical feasibility and current capabilities of the NOx controls. Staff also conducted 16 site visits to assess any potential challenges and cost impacts of implementing NOx controls. For the boilers and process heaters category, staff identified two major NOx technologies, ULNB/LNB and SCR. ULNB/LNB can be classified as combustion control and SCR as post-combustion control.

In most cases, post-combustion technologies may be utilized in conjunction with combustion control technologies to achieve maximum NOx reductions. Minimizing NOx formation at the source will in turn reduce the NOx inlet to the SCR. A well designed and engineered SCR can achieve up to 95% reduction efficiency and by employing both burner control and SCR, it will achieve the maximum degree of NOx reduction as required by BARCT.

Most of the process heaters in the category are equipped with first generation LNB. Advancements have been made over the last 30 years that have improved their performance. Newest generation of burner control will typically yield NOx in the 20 to 35 ppmv range with RFG. Based on compliance tests of recent ULNB installations at a local refinery, NOx can be in the low to mid 20 ppmv range. The latest SCR technology with proper engineering and design can achieve up to 95% removal efficiency – both based on recent permit applications at an existing refinery. One of the challenges of LNB/ULNB is that some heaters are not suitable for LNB/ULNB retrofits due to specific constraints of the heater such as firebox size and floor spacing, turndown requirements, and proximity to process tubes.

To assess performance of existing burner performance, staff evaluated existing heater performance for units with burner control only. The tables below summarize staff's findings for existing burners installed on process heaters.

Table B-7. Burner performance based on age using refinery gas

Burner Observations for Existing Heaters (Refinery Fuel Gas)	
Traditional Burners (Premix or Raw Gas)	Highest NOx (75 to 134 ppmv)
>25 years old (LNB/ULNB)	High NOx (60 to 80 ppmv)
<25 years old (LNB/ULNB)	Low NOx (20 to 47 ppmv)

Based on current data and information, older first generation LNB/ULNB installed in the 1980's or 90's, does not perform as well as newer generation LNB/ULNB. Meetings with burner manufacturers confirmed that recent generation designs have improved burner performance over the last 30 years.

Table B-8. Percentage of heater with existing burner control

Existing Heaters (Refinery Fuel Gas)		
Heater Size Category (MMBtu/hr)	Percent of Equipped with LNB/ULNB	NOx Range (ppmv)
<20	88%	20 to 40
≥20 to <40	90%	15 to 80
≥40 to ≤110	83%	17 to 70
>110	97%	22 to 70

Based on the information in the table above, many of the heaters are already equipped with burner control technology, and it is suggested that the LNB/ULNB in existing heaters are designed and installed in accordance with the American Petroleum Institute (API) 560 recommended guidelines for fired heater refinery service. Thus, retrofitting these existing burners to the latest generation LNB/ULNB should not require major modifications.

SCR technology achieves the highest NOx removal efficiency and is commercially available. The technology is proven and utilized throughout various industries for NOx control. Catalyst technology has advanced over the last 30 years and along with understanding of ammonia injection, tuning, mixing/distribution, it has greatly improved the performance of the system. Most SCR manufacturers will use CFD and Cold flow modeling to maximum mixing. Based on recent permit applications at one refinery, a 96% reduction efficiency can be achieved with a single layer.

Initial BARCT Emission Limit and Other Considerations

The recommendation for the BARCT NOx emission limits is established using information gathered from existing South Coast AQMD regulations, existing units permitted in South Coast AQMD, regulatory requirements for other air districts, and the technology assessment. Both retrofit and new installations are considered. Once the initial limits are established, a cost-effectiveness determination is made at that initial limit. If the initial limit is not cost-effective, an alternative limit may be recommended. Unique circumstances are taken under consideration to distinguish alternative limits or to create provisions in the rule to address equipment that would otherwise not be cost-effective. Based on conversations with technology vendors and recent installations, staff concluded that 2 ppmv NOx is achievable. Newer generation LNB/ULNB can achieve 30 to 40 ppmv NOx and if a properly designed SCR system is applied that can achieve 95% reduction, 2 ppmv is technically achievable.

Cost-Effectiveness and NOx Control Technology Cost

For process heaters and boilers category, staff determined that the most effective technologies for reducing NOx emissions is a combination of LNB/ULNB and SCR. This is based on the concept that reducing the NOx at the point of generation will reduce NOx inlet into the SCR, thus a lower NOx in the SCR outlet. These two technologies when engineered and designed properly can achieve 2 ppmv NOx. In order to estimate total installation costs (TIC) for a SCR, staff used the U.S. EPA SCR cost spreadsheet. The spreadsheet uses input parameters to generate an estimated TIC. TIC is then used to calculate the cost-effectiveness using the DCF method described previously. However, one limitation to U.S. EPA SCR cost spreadsheet is that it was originally designed and based on the electric power generating sector – gas turbines SCR installations. Total Installation Cost (TIC) for SCR installations in the refining sector can be up to 10 times more expensive due to the limited space within processing units; some facilities have performed elaborate SCR engineering designs to install their SCRs. As a result of space and engineering requirements, TIC cost that a refinery incurs increases significantly compared to the electric power generating sector. To reflect the actual TIC of SCR installations in the refinery sector, staff modified the U.S. EPA SCR cost spreadsheet using actual TIC estimates provided by the facilities. Staff consulted with U.S. EPA Air Economics Group regarding staff's proposed methodology for revision of the SCR cost spreadsheet. Staff's revised methodology was approved and endorsed to reflect the change for the refinery sector.

Staff received two series of costs data submitted by facilities, in 2018 and 2021. The first cost data submission in 2018 by facilities consisted of data for 80 SCR projects, however staff excluded any provided costs that were for SCR catalyst replacements only – typical SCR catalyst requires replacement every 4 to 5 years and is considered an operation and maintenance (O&M) cost. The costs in the first submission were a mix of conceptual design cost estimates (+/- 50% accuracy) and detailed engineering cost estimates (+/- 10 accuracy) for projects due to the 2015 RECLAIM NOx shave. Staff assumed all costs received from facilities included capital, engineering, construction, tax, and shipping. In addition, all submitted costs were assumed to include increased labor costs associated with Senate Bill (SB) 54 which requires refineries to use unionized construction labor. Provided TCI costs were in different years, and therefore, staff escalated all cost at 4% inflation to 2018-dollar year to ensure costs were equivalent to one another. Below is the distribution of cost received based on equipment size.

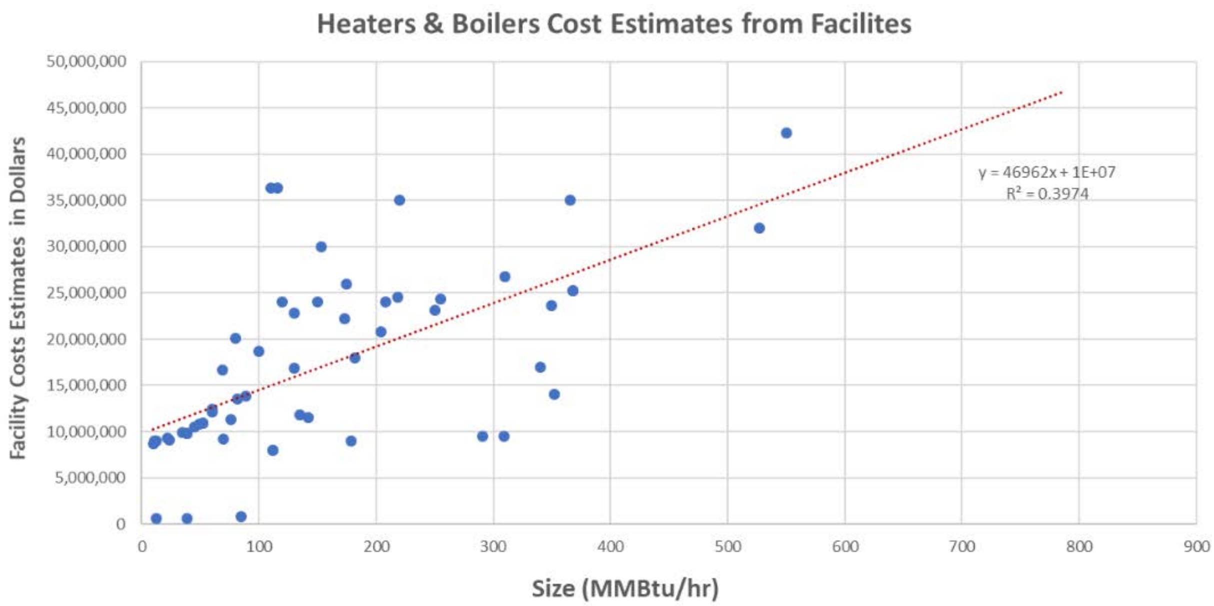


Figure B-4. SCR TIC costs provided by facilities versus corresponding heater/boiler sizes

Consistent with the methodology used in U.S. EPA cost spreadsheet, staff used the cost data provided to generate a cost curve below by dividing the TCI by the heater size to determine a cost per MMBtu/hr. Once the cost curve was generated, the curve equation was used to revise the total capital investment equation used in the U.S. EPA SCR cost spreadsheet. The equation and cost calculation used in the U.S. EPA SCR cost spreadsheet is based on the 0.6 power factor rule or "Rule of Six-tenths". Staff reached out to U.S. EPA Air Economics Group, Office of Air Quality Planning and Standards (OAQPS) regarding staff's proposed revision to the SCR model; the methodology proposed by staff to come up with a suitable TCI equation was endorsed. Staff discussed the methodology of revising the spreadsheet in Working Group Meeting #8 on June 27, 2019 and Working Group Meeting #9 on December 12, 2019. The SCR spreadsheet was used to estimate SCR cost for units where costs were not submitted or provided to staff. If the facilities provided cost for a unit, staff used the provided costs in the cost-effectiveness calculation. Some costs were provided for multiple heaters venting to a common SCR. For these heaters, staff summed the heat input for all heaters and divided the sum by the total cost for the SCR. Using the Rule of sixth tenths or 0.6 power factor rule (below), a cost for a project can be estimated based on a known cost. This methodology forms the basis of the U.S. EPA SCR cost model that was used to estimate cost for SCR projects at refineries.

$$C_B = C_A\left(\frac{S_B}{S_A}\right)^N$$

C_B = approximate cost of equipment having size S_B (MMBtu/hr, hp, scfm, etc.)

C_A = known cost($) of equipment having corresponding size S_A (same units as S_B)

(S_B/S_A) = ratio size factor

N = size exponent (varies 0.3 to >1.0, but average is 0.6)

Figure B-5. Rule of Six-tenths (0.6 Power Factor Rule)

The Rule of Six-tenths or 0.6 power factor rule is an equipment cost estimating method to determine an order of magnitude estimate, study estimate, or preliminary estimate and serves as a cost indicator at an early stage of the design. The rule of six tenths is not meant to be a definitive or detailed estimate of a project, those are major undertakings that require conducting a detailed engineering study and obtaining formal quotes and competitive bids from vendors for the project scope. The rule of six tenths is a ratio and proportion estimating method; ratio assumes that the relationship between the two things such as quantity, size, or amount. Proportion assumes that the two items are similar only differing in magnitude. Using the Rule of Six-tenths, approximate costs can be obtained if the cost of a similar item of different size or capacity is known. As part of the revised cost estimates provided to staff, the facilities provided some costs for actual SCR projects that are nearing completion or currently in the constructions phase – these were detailed estimates and provided an indication of a typical cost for a SCR project. However, majority of the cost were a mixture of project scope or order of magnitude cost estimate but based on Norton Engineering's review of the cost data provided to staff, the cost data were considered acceptable and reasonable considering potential complexities of SCR installations.

Once staff separate SCR projects, ULNB/LNB projects, and other post-combustion projects, staff proceeded to determine the "N" exponent that is more representative of the actual cost data provided. The "N" exponent is the size factor used to ratio and estimate cost from a known cost. The size factor exponent will vary from 0.3 to 1, but on average is near 0.6, hence the six-tenth or 0.6 power factor rule. In order to determine the "N" exponent, staff plotted the cost data and generated a power curve with all the cost data for a specific NOx control (Figure B-5 and B-6). From the power curve, an equation was obtained and the exponent in the equation is the "N" exponent used to revise the EPA SCR cost model that will be used to estimate SCR costs. The equation generated from the ULNB/LNB cost curve will be used to estimate burner costs.

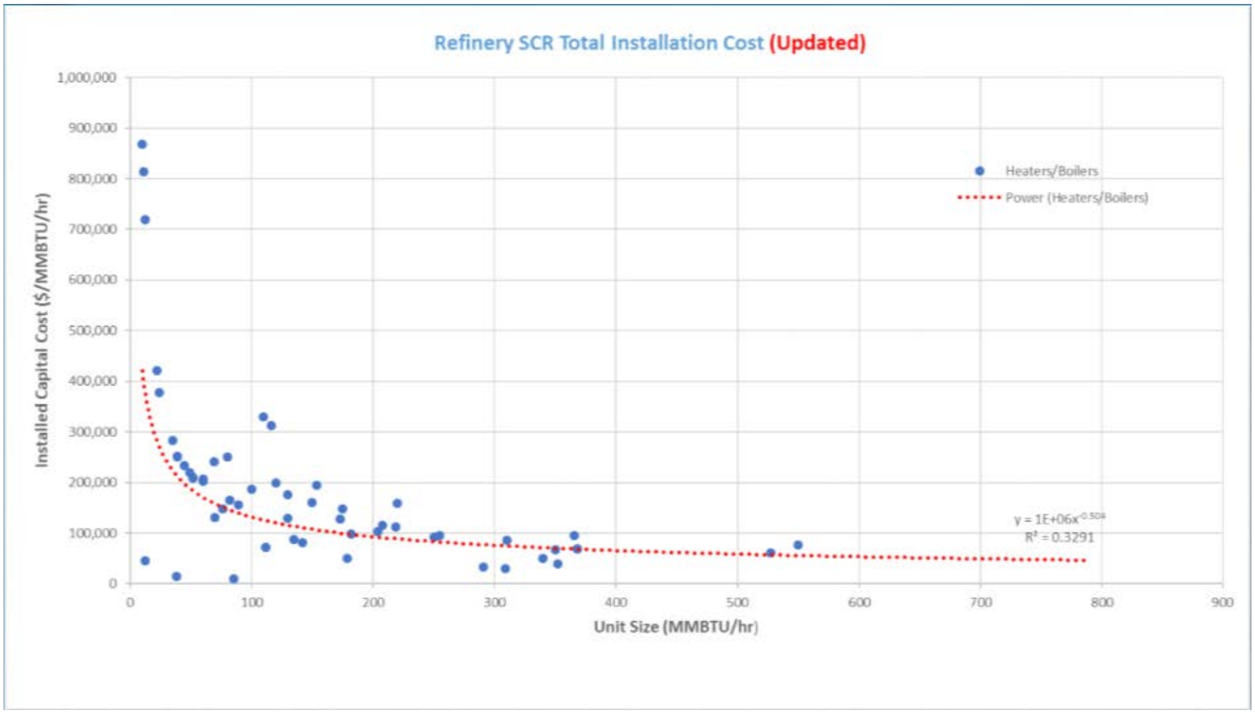


Figure B-6. Cost curve used to revise U.S. EPA SCR cost spreadsheet

Staff's initial assessment concluded that a combination of LNB and SCR can achieve 2 ppmv. Staff also concluded that since 90% of existing heaters currently have LNB or ULNB installed, there should not be any major issues to upgrade to newer generation burner technology. Upgraded burners will reduce inlet NOx emissions to the SCR and will yield between 30 to 40 ppmv NOx in heater applications. Staff concluded that burner control is feasible for most units and when applied in combination with a properly engineered SCR, it can achieve 92% or greater reduction, and thus, 2 ppmv is technically feasible. Staff added the additional cost of burner control to those units that required greater than 92% reduction efficiency.

For the cost of burner control , staff used a similar approach to estimate the cost of SCRs. As part of the first cost data submittal, staff requested TIC from facilities for existing LNB/ULNB projects. Facilities provided cost estimates for 13 installations and cost estimates ranged from $1.6MM to $9.8 MM. Costs were divided by unit size and plotted as a power curve. Figure B-6 demonstrates the curve that was generated and used to estimate burner control costs for a typical process heater and boiler application.

Burner controls for SMR heater applications are slightly different in design from that of a traditional process heater or boiler. SMR heaters operate at a higher temperature than a typical process heater and fuel can potentially contain up to 30% hydrogen (PSA-off gas) which will typically yield higher NOx at the burners. NOx can range from 40 to 50 ppmv, thus staff concluded that a 5 ppmv NOx limit is appropriate for the SMR heater category when SCR is applied as a NOX control option. In addition, SMR heaters typically have a larger number of burners when compared to a traditional process heater, so TIC will be higher.

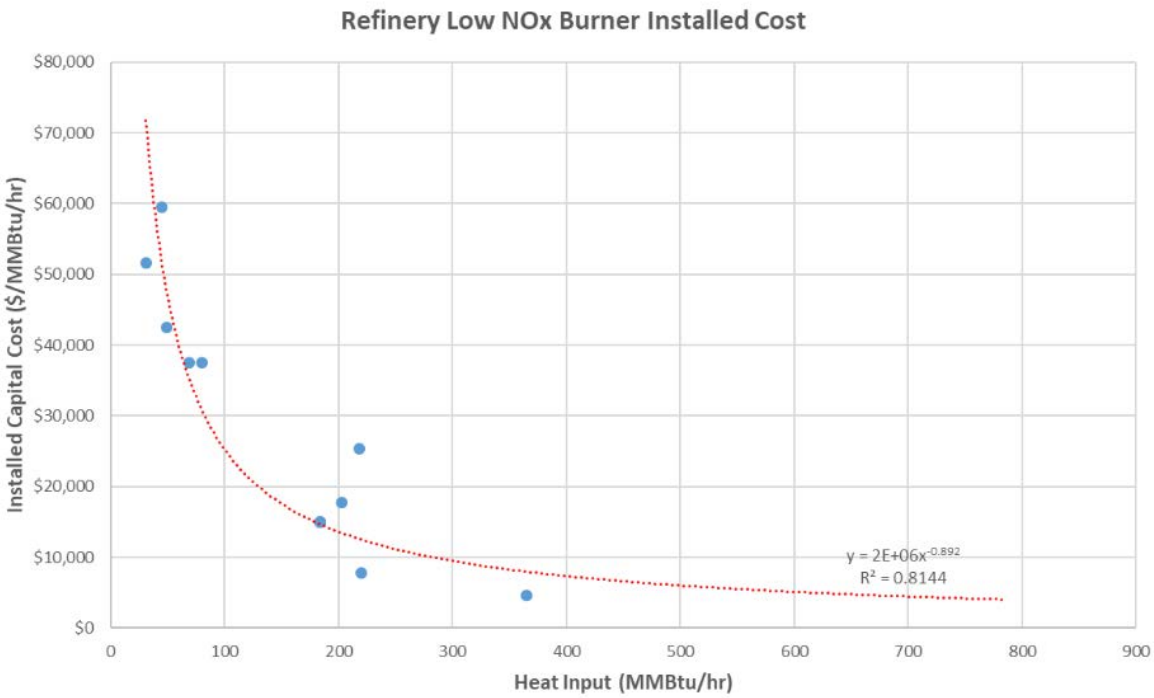


Figure B-7. LNB/ULNB Cost-Curve Used to Estimate Burner TIC For Boilers and Process Heaters

Staff generated the cost curve in Figure B-7 based on the cost estimates provided by facilities and meeting with burner manufacturers that specialize in SMR heater applications. The manufacturers stated that typical costs for an SMR heater LNB retrofit are typically twice the cost of traditional process heater LNB retrofit, so staff made the adjustments in Figure B-7 to reflect those costs. Figure B-7 shows the cost curve generated for a traditional refinery process heater versus a SMR heater and it shows that staff's overall cost estimates for a SMR LNB retrofit application will typically be twice as much as a traditional process heater application. The cost curve was used to generate cost estimates for units requiring LNB retrofits for SMR heaters – units that require greater than 92% reduction. However, since most of the heaters in the SMR category are currently equipped with some form of NOx control or LNB, staff anticipates that most of them will only require an SCR upgrade. For the cost of an SCR upgrade, staff estimated the cost to be 25% of a completely new SCR retrofit and assumed a 10 percent increase in O&M to account for increased cost of catalyst replacement, reagent usage, and electricity. This cost assumption for an SCR was also applied to all process heaters and boilers that require an SCR upgrade to meet the proposed BARCT. Staff used the modified U.S. EPA SCR cost model to generate a cost and then used 25% of cost generated for SCR upgrade costs. However, based on comments received from Norton Engineering, staff updated the SCR upgrade cost estimates. Staff initially estimated that the costs for a SCR upgrade would range between $4 MM to $7.1 MM but updated the range to $7.5MM to $10MM based on Norton Engineering's suggestion. Staff updated the cost-effectiveness for SMR category based on the new cost estimates.

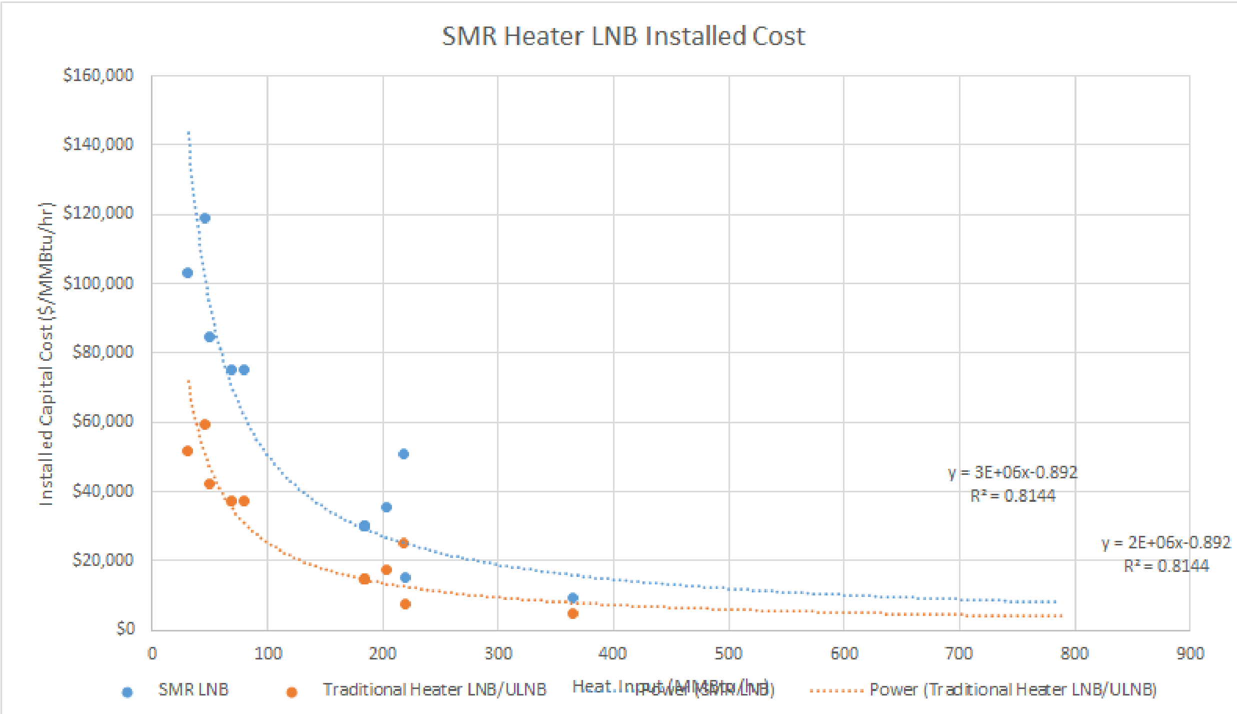


Figure B-8. LNB cost curve for SMR heaters versus traditional heaters

Once staff established the cost estimate methodology that was representative of the refining industry, staff proceeded with the cost-effectiveness analysis. Staff conducted separate cost-effectiveness analysis for the boiler and process heaters categories. For both cost-effectiveness analyses, if a facility provided cost estimates for a specific unit, staff used that cost. Staff only applied the previously outlined cost estimate methodology if the cost for a unit was not provided – approximately 75% of the cost used in the analysis were provided by facilities. The first or initial cost effectiveness analysis was based on the first cost data submission and the second cost-effectiveness analysis is based on the second cost data submission in March 2021.

Initial Cost-Effectiveness for Boiler and Process Heater Category

Based on the first cost data submission, staff presented the initial BARCT assessment for the process heaters and boilers in Working Group Meeting #9 on December 12, 2019, and a follow up in Working Group Meeting #10 on February 18, 2021. At WGM #9, staff established the 2017 as the baseline year for emissions. The 2017 baseline was established based on the most recent data available at the start of the rulemaking process. Furthermore, during discussions at Working Group Meeting #8 held on June 27, 2019, staff presented the methodology to calculate operational peak (maximum NOx concentration) for units that did not have a permit limit. The permit limit and operational peak were used to calculate cost-effectiveness for each category. Stakeholders expressed concern and requested that staff use annual average stack NOx concentration reported in the 2018 surveys as the basis for the cost-effectiveness calculation rather than the permit limits or operational peak proposed by staff. Stakeholders stated that it is more representative of unit operation and should be the basis for the cost-effectiveness calculation. Stakeholders expressed concern that use of permit limits or operational peak can potentially overestimate the emissions inventory and did not support using operational peak or permit limits for cost-effectiveness calculations. The tables below show the initial cost-effectiveness analysis based on the first cost submission for process heaters and boilers category.

Table B-9. Initial Cost-Effectiveness Assessment for Each Heater Class and Category

Heaters Cost-Effectiveness (First Cost Submission)				
	2 ppmv	**9 ppmv**	**30 ppmv**	**BARCT Limit (ppmv)**
Heaters (<20 MMBtu/hour)	$308,000	$212,421	$276,000	40/9
Heaters (≥20 - <40 MMBtu/hour)	$84,000	$78,000	$50,000	40/9
Heaters (≥40 - ≤110 MMBtu/hour)	$56,000	--	--	2
Heaters (>110 MMBtu/hour)	$40,000	--	--	2

Table B-10. Initial Cost-Effectiveness Assessment for Each Boiler Class and Category

Boilers Cost-Effectiveness (First Cost Submission)				
	2 ppmv	**5 ppmv**	**9 ppmv**	**BARCT Limit (ppmv)**
Boilers (<20 MMBtu/hour)	$94,000	$68,000	$56,000	40/5
Boilers (≥20 - <40 MMBtu/hour)	$512,000	$413,000	Achieved	40/5
Boilers (≥40 - ≤110 MMBtu/hour)	$50,000	--	--	2
Boilers (>110 MMBtu/hour)	$19,000	--	--	2

The initial cost-effectiveness analysis for boilers and process heaters determined that for units less than 40 MMBtu/hr it was not cost-effective to go to 2 ppmv, 5 ppmv, and 9 ppmv due to the low emission reductions. Staff proposed a BARCT limit of 40 ppmv since most units less than 40 MMBtu/hr are currently performing at or have permit limits near 40 ppmv; therefore, there will beno compliance cost for most of the units. Staff proposed a future BARCT limit of 9 ppmv for heaters and 5 ppmv for boilers once the current burners reach the end of their useful life or when 50% of the burners (heat input) is replaced. The facilities will incur some cost to upgrade the burners, but most of the cost will already be incurred due to end of useful life replacement. This assessment is based on emerging technology such as ClearSign™ and Solex™ from John Zink which can achieve single digit NOx emissions.

In a subsequent review of the process heaters, staff identified two process heaters within the less than 40 MMBtu/hour category that are currently performing above 40 ppmv. The NOx emissions for these two process heaters are approximately 58 ppmv and 96 ppmv with annual NOx emissions of 0.7 and 18.9 tons per year, respectively. These two heaters will incur compliance costs for retrofitting burner controls; burner cost estimates were from vendor quotes and revised burner cost-curve presented later in Figure B-13. Burner cost estimates were approximately $1.5 MM and $3 MM and based on the revised cost estimates, these two heaters are cost-effective to go to 40 ppmv or less. The cost-effectiveness is presented in Table B-11 below. An incremental cost-effectiveness analysis was not conducted since SCR was already determined not to be cost-effective for the less than 40 MMBtu/hour process heater category.

Table B-11. Cost-effectiveness for Process Heaters less than 40 MMBtu/hour Performing Higher than 40 ppmv

Process Heater Cost-Effectiveness for LNB/ULNB		
BARCT	**40 ppmv**	**Emission Reductions (tons per day)**
<40 MMBtu/hour	$16,000	0.031

Technical Feasibility of Proposed BARCT limit of 2 ppmv

Staff contracted two engineering consultants; Norton Engineering Consultants (NEC) and Fossil Energy Research Corporation (FERCo). Each consultant was tasked to conduct a separate independent analysis – Norton Engineering was tasked with the review of staff's BARCT assessment and FERCo was tasked with conducting site visits to assess the space constraint challenges with NOx control installations. The consultants' final assessment reports were released in December 2020 and both consultants presented their findings at Working Group Meeting #16 on December 10, 2020. The final reports supported staff's BARCT assessment conclusion that 2 ppmv is technically feasible for the process heaters and boilers greater than or equal to 40 MMBtu/hr category. ULNB when combined with SCR, can reduce the NOx inlet into the SCR which in turn will reduce the overall size of the SCR and related equipment such as reagent usage and catalyst quantity. Lower NOx inlet into the SCR will translate to a lower NOx outlet. Based on the Norton Engineering report, LNB/ULNB vendor guarantees are typically between the 20 to 50 ppmv NOx range for refinery fuel gas. Under sub-optimal conditions, the guaranteed levels typically fall in the 32 to 38 ppmv range. However, Norton Engineering did mention that on occasion, burner retrofit have been unable to achieve less than 50 ppmv. Stakeholders immediately expressed significant concern with the conclusions and the proposed BARCT limit of 2 ppmv by South Coast AQMD staff.

Refinery stakeholders questioned the technical feasibility of achieving 2 ppmv with ULNB and SCR combination despite the third-party engineering's support of staff's conclusions. Torrance refinery and Tesoro Refinery submitted comment letters regarding staff's conclusion. The Torrance refinery comments letter stated that there is not a "one-size-fits-all" technology that can guarantee same or similar results for all refinery process heaters and boilers in operation. Every unit should be evaluated on a case-by-case basis to determine a unit's ability to accept ULNBs. Retrofitting an ULNB is not as simple as pulling out the older burner and installing a new one.

There is much more that needs to be considered as part of the engineering and purchasing decision process. This can have an overall impact on the technical feasibility of achieving 2 ppmv. When considering or evaluating burner retrofit projects a facility must not only look at the burner, but also into other interrelated areas and current dynamics surrounding the existing process heater.

Marathon (Tesoro Refinery) in their comment letter submitted on February 1, 2021 provided information from an independent technical feasibility analysis that was conducted to address the proposed NOx emission limit by staff for refinery heaters greater than or equal to 40 MMBtu/hr. The comment letter included several attachments to substantiate the technical analysis. Comments centered around the key issues of technical feasibility, safety, and cost of NOx emissions controls for BARCT. The comment letter stated that South Coast AQMD's BARCT technology selection of ULNB and SCR for 2 ppmv are not technically feasible for most installations and presents unacceptable safety hazards on the broad universe of process heater designs within a refinery. Marathon (Tesoro Refinery) stated that there is inherent operational variability with refinery process heaters and staff's conclusions disregard the physical design characteristics that can impact safety and performance. The Tesoro Refinery letter highlighted concerns and feasibility of ULNB retrofit such as:

- Risk of flame impingement and safety
- Air preheater impact on ULNB performance
- Heater turndown and variable heat input operation
- Dynamic changes in fuel gas composition
- Physical features such as configuration, geometry, and firebox dimensions

The Marathon (Tesoro Refinery) comment letter also included a technical assessment of feasibility considerations for NOx emissions control retrofit which highlighted API and company specific standards for safe heater design, operation, and maintenance. The American Petroleum Institute (API) provides recommended guidelines for optimal operation of refinery fired heaters and burners in API 560 for fired heaters and API 535 for burners. The recommended guidelines include heat density and minimum burner spacing for optimal operation and safety, if any of these criteria are not meet, there can be an impact on actual NOx performance and operational safety, as described below:

- A higher heat density can result in higher flame temperatures and therefore increase NOx emissions.
- If burner spacing is not adequate, this can lead to flame interactions or coalescing which results in increased NOx emissions and potential impingement of tubes which can result in tube failures and lead to potential process safety issues.
- Not operating within these guidelines is considered "suboptimal" which can impact burner performance and safety.

Staff has acknowledged early in the rule development that not all heaters may be candidates for LNB/ULNB retrofits. In Working Group Meeting #6 held on January 31, 2019 staff presented the following discussion:

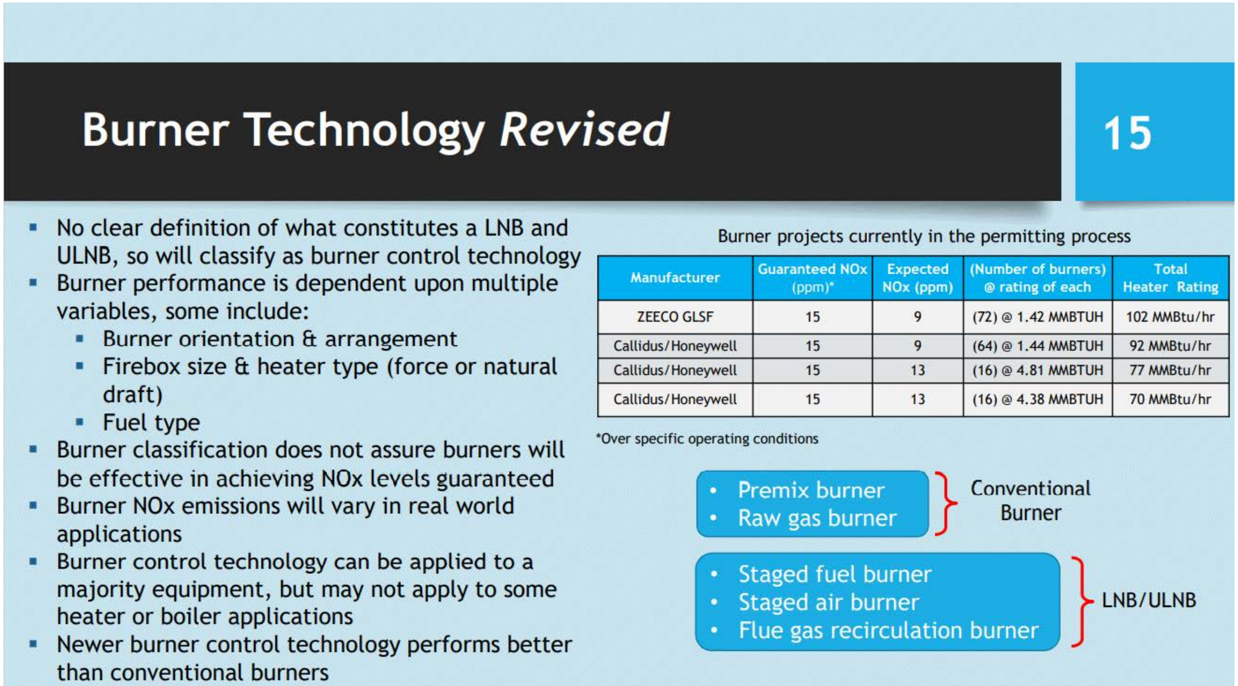


Figure B-9. Slide from Working Group #6

Norton Engineering's report further acknowledged that under optimal conditions, 30 ppmv NOx can be achieved with ULNB. However, under suboptimal installations, a burner will perform in the 40 to 50 ppmv range provided there is no potential for tube impingement. Based on stakeholder feedback regarding the challenges and installation of ULNB in older process heaters, staff consulted with Norton Engineering, FERCo, and SCR catalyst manufacturers regarding the feasibility issue raised by stakeholders. Consultants stated that regardless of ULNB NOx performance, 2 ppmv is feasible by installing multiple catalyst reactors with multiple ammonia injection grids (AIG) or static mixer in between each reactor. SCR catalyst manufacturers confirmed that these two stage reactor designs are used commercially in nitric acid plants where NOx emissions can be upwards of 4,000 ppmv and NOx removal efficiencies from this state-of-the-art design are 98% or greater. This alternative two stage SCR design was presented and discussed at working group meeting #17. Staff re-assessed the cost-effectiveness for a dual stage SCR based on the following assumptions:

Table B-12. SCR Cost Reassessment from Working Group Meeting #17

SCR Cost Effectiveness Reassessment		
SCR Design Parameter	Cost Increase	Comments
Catalyst Increase	30% of Catalyst Cost	Addresses the potential need of additional catalyst
Multiple Stage Reactor with additional AIG or Static Mixer	25% of Total Installed Cost (TIC)	Addresses potential cost increase of additional catalyst, reactor, and installation
Increase O&M	25% of O&M	Addresses potential increase in ammonia consumption and electricity needed for larger fan associated with multiple beds of reactors
Annual Tuning	Additional $40k added to annual O&M costs	Addresses the proper mixing and distribution

For all process heaters and boilers requiring greater than 92% NOx reduction, staff removed the cost of ULNB and replaced the cost for a second stage reactor arrangement based on the re-assessment assumptions above. The reassessment of the cost-effectiveness for the alternative pathway that uses a dual stage reactor SCR to achieve 2 ppm is shown below; it was still cost-effective to achieve 2 ppmv with a dual stage SCR reactor arrangement.

Table B-13. Cost-Effectiveness Reassessment Using Dual Stage Reactor

Equipment Class	NOx Limit	UNLB/SCR	Dual Reactor
Heaters 40 – 110 MMBtu/hr	2 ppmv	$35,000	$39,000
Heaters > 110 MMBtu/hr	2 ppmv	$35,000	$44,000
Boilers 40 – 110 MMBtu/hr	2 ppmv	$49,000	$48,000
Boilers > 110 MMBtu/hr	2 ppmv	$12,000	$15,000

Refinery stakeholders immediately raised the concern that staff did not consider space availability and constraints for this type of design. Refineries cannot accommodate a second SCR reactor which makes the alternative pathway not technically feasible. In addition, stakeholders stated that staff underestimated costs for a two-stage arrangement; cost for this design can be 80% more than a typical single reactor SCR. In response to stakeholder concerns, staff concluded that a higher NOx limit of 5 ppmv will likely address those concerns. For most devices in the process heater and boiler category, a 5 ppmv NOx limit will only require a single reactor SCR system and 5 ppmv NOx limit has been demonstrated with several units already meeting the limit. A NOx limit of 5 ppmv would achieve 90 percent of the estimated NOx reductions of 2 ppmv. A 5 ppmv NOx limit will also alleviate the concerns and challenges of utilizing a ULNB.

Revised Cost-Effectiveness Based on Second Cost Data Submission

At the February 2021 Stationary Source Committee facilities requested that staff consider revised cost data. Staff gave a submittal deadline of March 12, 2021, for facilities to submit revised cost data and state that each cost data should be specific to the project to meet the targeted NOx limits. The submitted revised cost data will be reviewed by Norton Engineering, incorporated into the U.S. EPA SCR cost estimator, revise the BARCT assessment for the process heaters and boilers category. Furthermore, staff also stated in Working Group Meeting #19 held on March 4, 2021 that an evaluation of outlier units that are currently operating near 5 ppmv and low-use units will also be incorporated. The identified devices must accept an alternative limit in the permit and will be exempt from the 5 ppmv NOx limit. At Working Group Meeting #21 staff state the following conditions for devices when developing these conditional limits:

- Conditional limits are for units that currently have NOx control technology and achieving near the proposed limits
- In lieu of meeting the proposed BARCT limit, operators can accept permit limits at the conditional limit
- Devices must already meet the conditional limit and cannot retrofit new NOx controls to meet the conditional limit

As part of the cost-effectiveness reassessment based on the revised cost data, staff modified the BACRT analysis to integrate the incremental cost-effectiveness.

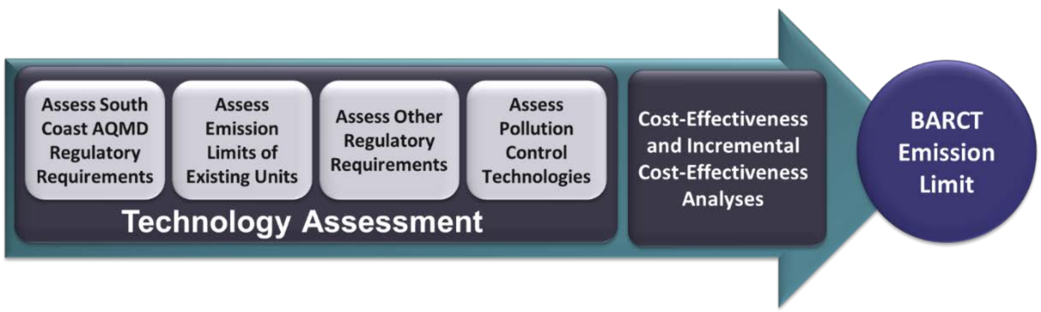


Figure B-10. BARCT Assessment Approach

As part of the March 2021 revised cost data submission, staff received 108 new or revised SCR estimates for the heaters and boilers; Data also included cost for SCR upgrades and ULNB/LNB projects for a few units. Staff received cost for 58 SCR projects in the first cost submission. Majority of the facility revised cost data was for heaters and boilers greater than or equal to 40 MMBtu/hr but also included cost for other category of equipment. SCR cost for the boiler and heater category ranged from $2 MM to $70 MM.

As part of the revised cost, staff requested the assistance of Norton Engineering for review of the cost data and provided the following comparisons:

- Revised burner costs were compared against a “typical” cost curve for burner upgrades
- Refinery’s initial cost data compared to Norton Engineering’s escalated cost estimates from the 2014 NOx RECLAIM BARCT feasibility study
- Refinery’s revised cost data compared to Norton Engineering’s escalated cost estimates from the 2014 NOx RECLAIM BARCT feasibility study (shown in graph below)
- Ratio of the refinery’s initial and revised costs data

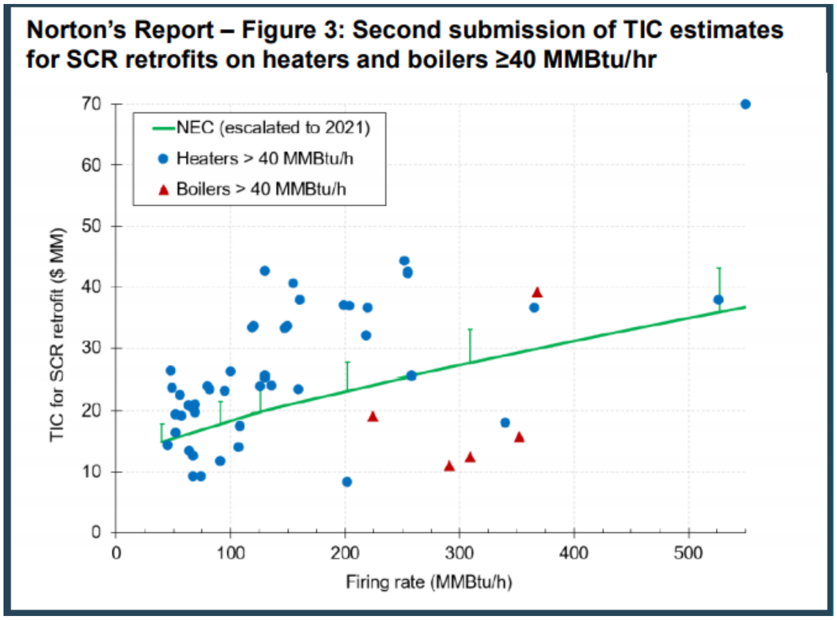


Figure B-11. Norton Engineering Report, second TIC submission

Norton Engineering's review and feedback regarding the facility revised cost data was presented in Working Group Meeting #22 on June 30, 2021. Norton Engineering's conclusion was that the costs provided by the facilities are not unreasonable, considering the potential complexity.

Facility-Revised Burner Costs

- Most of the facility-revised cost data for burners was consistent with "typical" costs
- 15 of the estimates were within expected range and 5 were outliers

Facility-Revised SCR Costs

- Norton's estimated SCR costs roughly passes through the middle of the refinery's initial cost data but is at the lower end of the facility-revised data
- 15 facility-revised datapoints were significantly higher
- Increases to the cost estimates are not unusual as project scope definition improves during the later stages of engineering design

Figure B-12 Facility Revised Burner and SCR costs

Based on Norton Engineering's recommendation, staff used all revised cost data submitted by facilities. Like the initial BARCT assessment, if cost for a specific device was provided, staff will use that cost in BARCT reassessment. In order to estimate costs for devices where costs were not provided, staff used all facility-revised data to update the power curve that will be used in U.S. EPA SCR cost model.

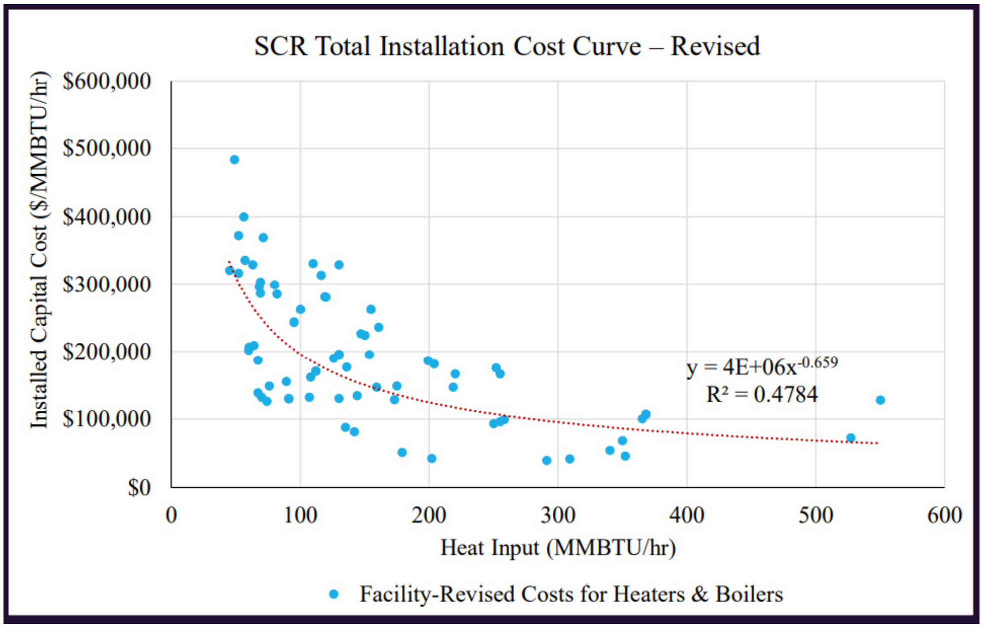


Figure B-13. Cost curve for SCR revised SCR TIC

Facilities also provided revised cost data for 20 LNB/ULNB projects. Staff used the revised cost data to update the cost curve used to estimate burner installations.

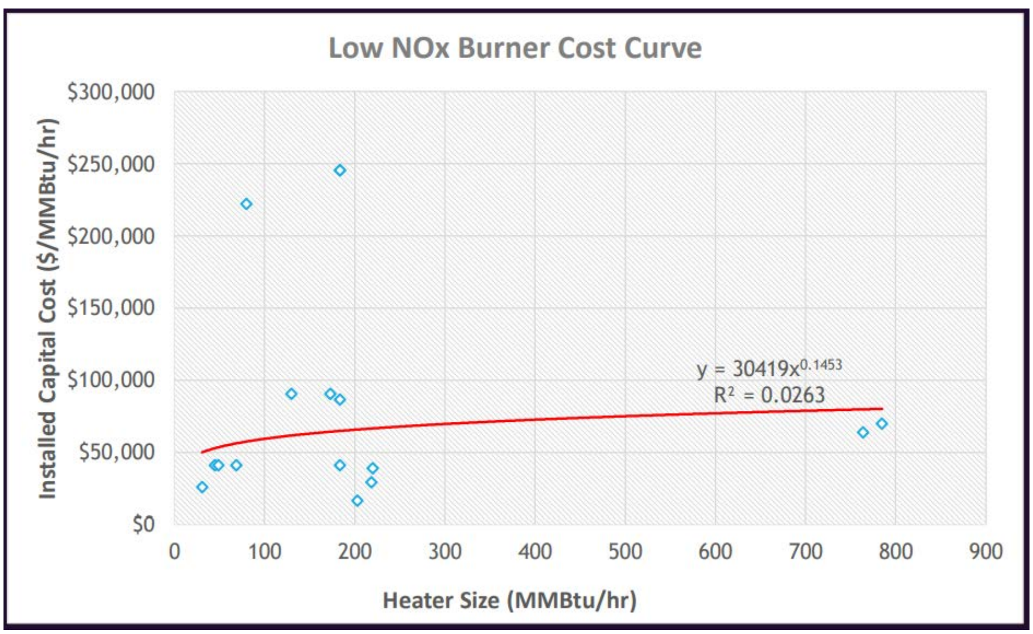


Figure B-14. Cost curve for revised LNB TIC

Once the cost estimate methodology has been updated, staff proceeded with the BARCT reassessment for the process heater and boiler category. Norton Engineering's final report concluded that sub-optimal burner conditions within a process heater will achieve 40 to 50 ppmv – this will be used to updates staff's prior conclusion that ULNBs can achieve 30 ppmv. The 30 ppmv is achievable under optimal conditions which are specified in API 535 recommended guidelines. In response to stakeholder feedback regarding the potential challenges and safety concerns of ULNB installation, the revised BARCT assessment will consider 50 ppmv as the achievable NOx level with burner control technology since this is the upper end of NOx range. The BARCT reassessment will be assessed as follows:

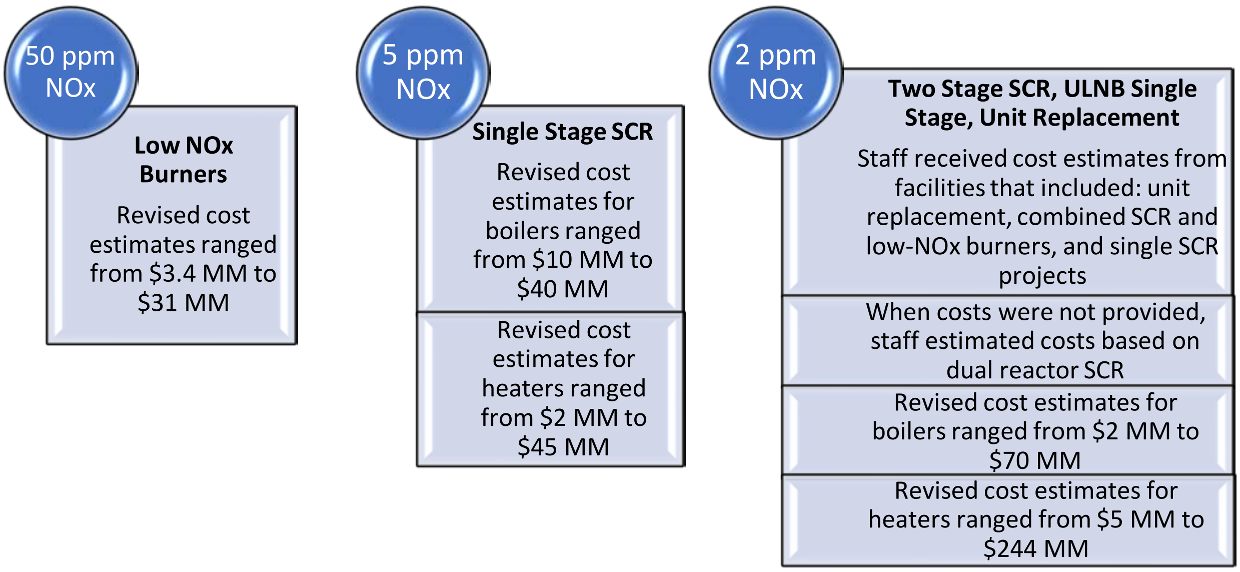


Figure B-15. BARCT reassessment for Process Heater and Boiler categories

Evaluating Conditional Limits

Based on the revised cost estimates provided by facilities, the average cost effectiveness to achieve ether 5 ppmv or 2 ppmv for heaters greater than or equal to 40 MMBtu/hr are above the $50,000 per ton of NOx. To reduce the average cost-effectiveness, staff proposed that devices operating between the proposed BARCT limit and conditional limits would not be required to meet the proposed NOx limit in Table 1 of the proposed rule; this applies to devices that are currently at or below the conditional limit. These conditional limits units are excluded from the cost-effectiveness calculation. An iterative process was used to identify the conditional limit NOx concentration level where the cost-effectiveness for devices above the conditional limit would be less than $50,000 per ton of NOx reduced. At 2 ppmv, no conditional limit was identified that will reduce the cost-effectiveness below $50,000 per ton of NOx reduced. At 5 ppmv, removing devices at or below the conditional limits will reduce the cost-effectiveness below $50,000 per ton of NOx reduced. Below is the iterative process used by staff to determine the conditional limits.

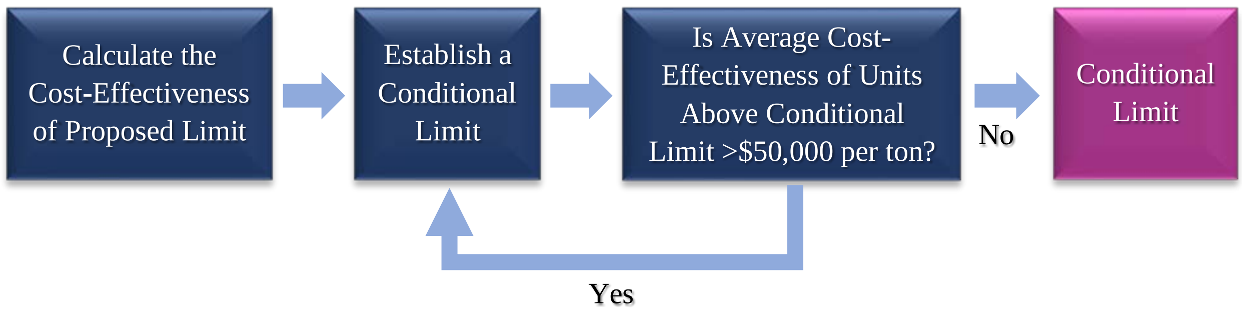


Figure B-16. Process of evaluating conditional limits

In the process of evaluating these conditional limits, staff identified several devices with combined stacks that consist of different sized heaters.

Staff also identified one unit greater than 110 MMBtu/hr that is operated at a low capacity of 12%. This unit has a high cost-effectiveness of $184,000 per ton of NOx reduced and low emission reductions at 0.02 tons per day. Staff will include a low-use provision exemption for devices operating less than 15% capacity – these low use devices will not be required to meet Table 1 limits in the rule.

In order to identify units that potentially qualify for the conditional limits, staff evaluated the NOx emissions reported in the 2018 survey. The NOx emissions reported in the survey are representative of the unit's annual average as reported by the facility. The conditional limits were presented at Working Group Meeting #22 on June 30, 2021. Stakeholders commented that staff should further evaluate the CEMS data based on a 24-hour rolling average for the conditional limit assessment; the evaluation will give a better representation of the unit's operation. Staff reassessed the CEMS based on the 24-hour rolling average recommendation while using the annual average in the survey as a screening step for further analysis of CEMS data. Below are staff's considerations when evaluating the CEMS data for a 24-hour rolling average:

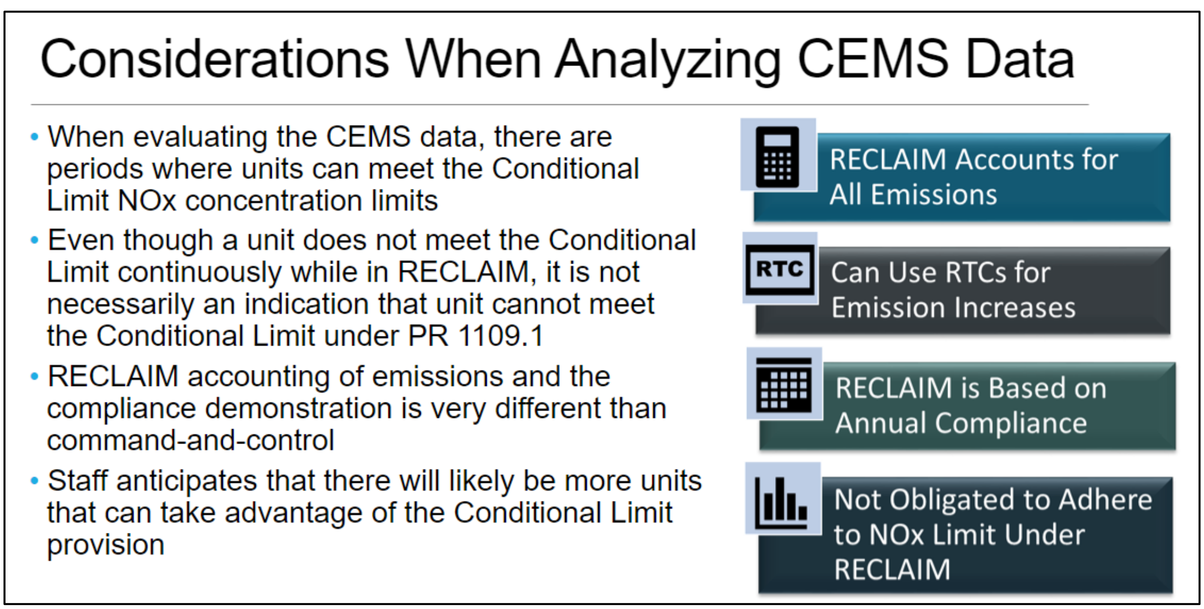


Figure B-17. CEMS data analysis considerations

Most of the units under RECLAIM do not have a permit limit, so there is no requirement to operate at a specific NOx level. However, during the CEMS analysis, any unit that had a permit limit typically operated below their permit limit 90% or more of the time. Staff believes this a good indication that under a command-and-control regulatory structure most of these units will be able to meet the BARCT limit or conditional limit. Staff identified units which are close to the conditional limit by using 80% as the threshold; if the conditional limit was 18 ppmv, then the CEMS for any unit performing at 14 ppmv of higher will be analyzed further. When analyzing the CEMS, staff conducted the conditional limit assessment in the following steps:

- **Step 1:** Identify units where the annual average NOx data is close to the conditional limit (80% of limit)
- **Step 2:** Identify and evaluate the percent of time a unit can achieve conditional limit over a 24-hour averaging period
- **Step 3:** If the unit cannot achieve the conditional limit for considerable amount of time, the unit will be removed
- **Step 4:** Re-assess the cost-effectiveness for category

Further CEMS analysis based on stakeholder feedback, identified three additional units as not close to the conditional limit. Staff removed each of the units form their respective categories and reassess the cost-effectiveness. Below is the result of the follow-up CEMS evaluation. The re-assessment table below was presented at a WSPA meeting held on August 6, 2021.

Table B-13. CEMS evaluation and reassessment for Process Heaters

Heater	Size (MMBtu/hr)	Annual Average NOx (ppm)	Proposed Conditional Limit (ppm)	Percent Below Conditional Limit (24-hr average)	Hours Below Conditional Limit (hours)
Heater 1	71.1	17.8	18	78%	6,708
Heater 2	52	14.7	18	86%	6,971
Heater 3	68	17.1	18	1%	6
Heater 4	82	17.6	18	38%	3,154
Heater 7	153	21.3	22	2%	127

The three heaters identified by staff were heaters 3, 4, and 7. Both heater 3 and 4 are in the 40 to 110 MMBtu/hr category and heater 7 is in the greater than 110 MMBtu/hr category. Staff re-assessed the initial conditional limit cost-effectiveness that was presented in Working Group Meeting #22.

Cost-Effectiveness and Conditional Limits

Process Heaters 40 to 110 MMBtu/hr

Staff used the iterative process at different concentration limits for the category and presented the analysis in Working Group Meeting #22 held on June 30, 2021. Staff initially identified 12 devices that are currently operating at NOx levels between 5 and 18 ppmv. Cost effectiveness for these units to meet 5 ppmv are high and range from $200,000 to $750,000 per ton of NOx reduced. The emission for these devices is low compared to other devices in category. Staff proposed a conditional limit of 18 ppmv for process heaters 40 to 110 MMBtu/hr and identified 12 heaters that qualified for the conditional limit. Excluding those units, the cost-effectiveness was less than $50,000 per ton as seen in the table below.

Table B-14. Potential Conditional Limits for process Heaters ≥ 40 - 110 MMBtu/hr

Process Heaters ≥ 40 - 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	Forgone Emission Reductions (tpd)
No Conditional Limit	$53,000	0/67 unit	None
10	$53,000	1/67 units	0.001
15	$51,000	8/67 units	0.02
18	$48,000	12/67 units	0.05

The re-evaluation identified two additional heaters that will potentially not meet the conditional limits in the 40 to 110 MMBtu/hr category. These two units were removed because they did not meet the 18 ppmv based on a 24-hour average and met the conditional limit less than 38% of time based on a 24-hour rolling average. The cost-effectiveness was reassessed in the table below.

Table B-15. Reassessment of Conditional Limits for process Heaters ≥ 40 - 110 MMBtu/hr

Process Heaters ≥ 40 - 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	Forgone Emission Reductions (tpd)
No Conditional Limit	$53,000	0/67 unit	None
18	$48,000	12/67 units	0.05
18	$50,500	10/67 units	0.02

After re-assessing the cost-effectiveness for the 40 to 110 MMBtu/hr category, the number of units staff identified as meeting conditional limit drops from 12 to 10 units and potential emission drops from 0.05 to 0.02 tons per day. The two units that were removed were placed back into the 40 to 110 MMBtu/hr category where the cost-effectiveness was recalculated and determined to be cost-effective at $50,500, so staff maintained the 18-ppmv conditional limit.

Once the cost-effectiveness and conditional limits were established, staff proceeded with the incremental effectiveness analysis where it was determined that going from 5 ppmv to 2 ppmv is above $50,000 per ton of NOx reduced.

Table B-16. Cost Effectiveness for Process Heaters ≥ 40 - 110 MMBtu/hr

Process Heaters 40 – 110 MMBtu/hr					
50 ppm		5 ppm		2 ppm	
Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)
$40,000	0.33	$50,500	1.66	$94,000	1.99

Table B-17. Incremental Cost Effectiveness for Process Heaters ≥ 40 - 110 MMBtu/hr

	50 -> 5 ppm	5 -> 2 ppm
Incremental Cost Effectiveness	$50,000	$293,000
Incremental Emission Reduction (tpd)	1.33	0.33

Process Heaters Greater than 110 MMBtu/hr

Like the 40 to 110 MMBtu/hr process heater category, staff assessed the greater than 110 MMBtu/hr category for conditional limit units. Some heaters in the greater than 110 MMBtu/hr have very high NOx emission reduction potentials and in order to minimize the amount of forgone emission reductions, staff considered two additional criteria for evaluating the conditional limit:

1. Concentration limit
2. Overall emission reduction potential for NOx control retrofit

Staff conducted the assessment using the iterative process at different concentration limits but for devices with a potential to achieve greater than 20 tons per year reduction were not excluded from the category as conditional limits – these units will have to retrofit to meet Table 1 limits if they are still operating at the conditional limit. Staff initially identified 17 units (4 units are common stack) that are currently achieving NOx levels between 5 and 22 ppmv with less than 20 tons per day reduction potential. The average cost-effectiveness for conditional limit devices is approximately $85,000 per ton of NOx. Average cost-effectiveness for conditional limit devices with potential reduction greater than 20 tons per year is $44,000 per ton of NOx to meet the 5 ppmv BARCT, so units with potential reduction greater than 20 tons per year will not be excluded from the cost-effectiveness calculation to meet the 5 ppmv NOx limit. Staff will include a conditional limit of 22 ppmv for those units that have a potential NOx reduction less than 20 tons per year. Process heaters greater than 110 MMBtu/hr that meet this criterion are eligible to take advantage of the conditional limit and not required to retrofit to the 5 ppmv BARCT NOx limit.

Table B-18. Potential Conditional Limits for Process Heaters > 110 MMBtu/hr

Heaters > 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	Forgone Emission Reductions (tpd)
No Conditional Limit	$56,000	0/51 unit	None
10	$55,000	5/51 units	0.03
15	$54,000	8/51 units	0.06
18	$52,000	12/51 units	0.15
20	$50,500	13/51 units	0.19
22	$50,000	17/51 units	0.23

The table above was also presented at Working Group Meeting #22 and after further CEMS analysis based on stakeholder feedback, identified one heater (heater 7) that did not meet the conditional limit. Staff removed that unit and placed it back in to the greater than 110 MMBtu/hr heater category where the cost-effectiveness was reassessed for the category.

Table B-19. Reassessment of Conditional Limits for process Heaters > 110 MMBtu/hr

Process Heaters > 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	Forgone Emission Reductions (tpd)
No Conditional Limit	$56,000	0/51 unit	None
22	$50,000	13/51 units	0.23
22	$49,800	12/51 units	0.21

After removal of heater 7 from the conditional limit category, the number of units meeting the conditional drops from 13 to 12 – this updated number of units was initially 17 but revised to 13 to reflect units that share a common stack. The potential additional emission reduction also drops from 0.23 to 0.21 tons per day and the category remains cost-effectiveness at $50,000 per ton of NOx. After establishing the conditional limit for the greater than 110 MMBtu/hr category, staff proceeded with the incremental cost-effectiveness analysis where going from 5 ppmv to 2 ppmv was determined to be greater than $50,000 per ton of NOx.

Table B-20. Cost Effectiveness for Process Heaters Process Heaters > 110 MMBtu/hr

Process Heaters > 110 MMBtu/hr					
50 ppm		**5 ppm**		**2 ppm**	
Cost Effectiveness	**Emission Reduction (tpd)**	**Cost Effectiveness**	**Emission Reduction (tpd)**	**Cost Effectiveness**	**Emission Reduction (tpd)**
$72,000	**0.07**	**$49,800**	**1.86**	**$110,000**	**2.22**

Table B-21. Incremental Cost Effectiveness for Process Heaters > 110 MMBtu/hr

	50 to 5 ppm	5 to 2 ppm
Incremental Cost Effectiveness	**$49,000**	**$400,000**
Incremental Emission Reduction (tpd)	**1.79**	**0.36**

Boilers Greater than or Equal to 40 MMBtu/hr

Staff conducted a BARCT reassessment for the boilers greater than or equal to 40 MMBtu/hr category based on 5 ppmv and revised cost data from facilities. The revised cost data for the boilers greater than or equal to 40 MMBtu/hr category and staff methodology to estimate cost is presented below:

Boilers 40 – 110 MMBtu/hr

- 3 boilers at one facility
  - 1 main boiler and 2 back-up
- Staff received capital cost from facility to achieve 5 ppm level of NOx
  - Used 4.5-time multiplier to account for installation costs (per Norton Engineering recommendation in the 2015 BARCT assessment)
  - Costs estimated ~ $10.5 MM
- For 2 ppm cost estimate, staff increased cost by 80% to account for two-stage SCR

Boilers >110 MMBtu/hr

- 20 Boilers
- Staff received eight revised cost estimates from facilities to achieve 5 ppm
  - Based on revised costs, SCR costs increased from $3 to $14 MM
- Costs included SCR upgrades or installations and ranged from:
  - $2.4 MM to $39 MM for SCR retrofits
  - $2 MM for SCR upgrades

Figure B-12. Boilers BARCT Reassessment

The BARCT reassessment was presented at Working Meeting #22 on June 22, 2021 and concluded that 5 ppmv NOx limit is cost effective for both the 40 to 110 MMBtu/hr category and greater than 110 MMBtu/hr category at $37,000 and $12,000 per ton of NOx, respectively. In addition, staff also stated that no outliers were identified for the category. In addition, cost-effectiveness to achieving both 2 ppmv and 5 ppmv were well below $50,000 per ton of NOx removed. 5 ppmv NOx was recommended by staff due to technical feasibility concerns of installing a two stage SCR system due to available space.

Table B-22. Cost Effectiveness for Boilers ≥ 40 - 110 MMBtu/hr

Boilers ≥ 40 - 110 MMBtu/hr					
50 ppm		5 ppm		2 ppm	
Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)
$13,000	**0.024**	**$25,000**	**0.049**	**$46,000**	**0.051**

Table B-23. Incremental Cost Effectiveness for Boilers ≥ 40 - 110 MMBtu/hr

	50 -> 5 ppm	5 -> 2 ppm
Incremental Cost Effectiveness	**$37,000**	**$656,000**
Incremental Emission Reduction (tpd)	**0.025**	**0.002**

The boilers 40 to 110 MMBtu/hr consist of three boilers located at one facility. These boilers currently do not have NOx controls, so no conditional limit is necessary for this category. Cost-effectiveness was calculated based on cost provided by the facility and is below $50,000 per ton of NOx. Staff's proposed BARCT limit for the category is 5 ppmv.

At Working Group Meeting #22, staff initially stated that no cost outliers were identified in greater than 110 MMBtu/hr category. However, upon review of the cost-effectiveness data and CEMS data, staff identified:

- Five boilers with a cost-effectiveness from approximately $75,000 to $8,000,0000
- Units performing at 7.5 ppmv or below based on CEMS annual average
- Based on CEMS analysis based on a 24-hour rolling average, all five boilers operate below 7.5 ppmv greater than 70% of the time (some were below >90% of the time)
- High cost-effectiveness due to low emission reductions (0.0001 to 0.007 tons per day)
- Providing a conditional limit of 7.5 ppmv will forgo 0.017 tons per day

Staff removed the five boilers operating below 7.5 ppmv based on a 24-hour rolling average and will include a conditional limit of 7.5 ppmv for the greater than 110 MMBtu/hr boiler category. The category remains cost-effective and drops from $12,000 to $11,000 per ton of NOx reduced.

Table B-24. Potential Conditional Limits for Boilers > 110 MMBtu/hr

Boilers > 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	Forgone Emission Reductions (tpd)
No Conditional Limit	$12,000	0/17 unit	None
7.5	$11,000	7/17 units	0.017

Staff reassessed the incremental cost-effectiveness after establishing the conditional limit of 7.5 ppmv for the greater than 110 MMBtu/hr category. Category remains cost-effective for 5 ppmv with the conditional limit units and incremental going from 5 ppmv to 2 ppmv is not cost-effective with the cost outliers removed.

Table B-25. Cost Effectiveness for Boilers > 110 MMBtu/hr

Boilers > 110 MMBtu/hr					
50 ppm		5 ppm		2 ppm	
Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)
$12,000	0.72	$11,000	2.19	$18,000	2.30

Table B-26. Incremental Cost Effectiveness for Boilers > 110 MMBtu/hr

	50 -> 5 ppm	5 -> 2 ppm
Incremental Cost Effectiveness	$11,000	$159,000
Incremental Emission Reduction (tpd)	1.47	0.11

Steam Methane Reformer Heaters

The SMR heater sub-category consist of eleven heaters and one SMR with an integrated gas turbine. Staff initially only included six SMR heaters that are fired primarily with PSA-off gas which has a higher hydrogen content. The hydrogen present can contribute to higher adiabatic flame temperatures which results in a higher NOx potential. The other five SMR heaters are fired exclusively on refinery fuel gas and originally included in the process heater category, but stakeholder commented that all SMR heaters should be in the SMR heater category regardless of fuel type. SMR heaters fired on refinery fuel gas are configured and operated similar to their PSA-gas fueled counterparts. All SMR heaters have:

- Large number of burners that are necessary to maintain even heat flux across the heater
- Similar design and arrangement
- Higher operating temperature than traditional process heaters – higher temperature needed to drive hydrogen reaction in process tubes

All SMR heaters are greater than 110 MMBtu/hr in size and are currently equipped with some form of NOx control except for two heaters that will require SCR. Five heaters in this category are performing at or below 5 ppmv NOx. Staff excluded any heater currently performing at or below 5 ppmv from the cost-effectiveness calculation. At Working Group Meeting #11 held on May 21, 2020, staff presented the initial BARCT assessment for six SMR heaters fueled by PSA-off gas. Staff evaluated both 5 ppmv and 2 ppmv. The initial cost-effectiveness only considered one unit that was performing above 5 ppmv; the other units are currently have controls and performing less than 5 ppmv and concluded that it was cost-effective for the unit to go to 5 ppmv with an SCR upgrade. Staff also determined that it was not incrementally cost-effective to go to 2 ppmv since it would require LNB replacement and a SCR upgrade.

Table B-27. Cost Effectiveness for SMR Heaters

Cost Effectiveness		
Heater Category	32 ppm (LNB & SCR Upgrade)	5 ppm 5 ppm (SCR Upgrade)
SMR and Gas Turbine **SMR Heaters**	$69,054 $138,781	Currently Performing $45,909

At Working Group Meeting #13 held on August 12, 2021, staff provided a follow up BARCT assessment to the SMR heater category that included all eleven units regardless of fuel type. Staff also conducted a new cost-effectiveness evaluation of the SMR heater category based on a 5 ppmv BARCT limit. In addition, staff also evaluated the CEMS using a 24-hour rolling average and concluded that most units are able to meet the 5 ppmv a majority of the time.

Table B-28. SMR Heaters Current NOx Control and Required Control to meet 5 ppmv

SMR Heater	Current NOx Control	NOx Control Required to meet 5 ppmv	Primary Fuel
1	LNB/SCR	SCR Upgrade	PSA
2	LNB/SCR	SCR Upgrade	PSA
3	LNB/SCR	No Action	PSA
4	LNB/SCR	No Action	PSA
5	LNB/SCR	No Action	PSA
6	LNB/SCR	SCR Upgrade	PSA
7	SCR	SCR Upgrade	RFG
8	SCR	SCR Upgrade	RFG
9	No SCR	New SCR Install	RFG
10	No SCR	New SCR Install	RFG
11	LNB/SCR	No Action	RFG

Three of the six SMR heaters fired on PSA-off gas currently meet 5 ppmv and require no action, so they were excluded from the cost-effectiveness. The other three units were included in the cost-effectiveness and required SCR upgrades. For SMR heaters fired on refinery gas, one heater currently meets the 5 ppmv and requires no action and excluded from the cost effectiveness. Two heaters will require SCR upgrades and two heaters will require brand new SCR installations – these four units were included in the cost-effectiveness.

Table B-29. Cost Effectiveness for all SMR Heaters to 5 ppmv

Cost Effectiveness for all SMR heaters (PSA off-gas and RFG)	
Heater Category	5 ppm
SMR Heaters	$15,041

Based on the BARCT reassessment for the SMR heater category, staff determined that it was cost-effective for the category to go to 5 ppmv. Staff proposed a BARCT of 5 ppmv at 3% O_2 based on a 24- hour rolling average. Stakeholders requested that staff re-evaluate the cost-effectiveness to retrofit units achieving near the proposed 5 ppmv BARCT limits based on the revised cost data submitted by facilities in March 2021. Staff presented and discussed the follow-up assessment at Working Group Meeting #21 held on May 27, 2021. Staff evaluated the annual average and CEMS data and identified several units that were performing near 5 ppmv. Staff estimated that SCR upgrade costs to be in the range of $4 MM to $7.1 MM, but based on the recommendation of Norton Engineering, staff increased the upgrade costs to $7.5 MM to $10 MM. Staff identified three outlier units that had high cost-effectiveness and low emission reduction of 0.015 tons per day.

Table B-30. Cost Effectiveness for SMR Heaters with low emission reductions

Cost Effectiveness
7.2 ppm -> 5 ppm NOx Limit
$242,000

Staff concluded that it was not cost-effective for these outlier units to retrofit to 5 ppmv, so staff proposed a near conditional limit of 7.5 ppmv for the SMR heaters. Staff removed these outliers from the SMR heater category evaluation and re-evaluated the costs for the remaining units.

Table B-31. Cost Effectiveness for SMR Heaters after taking outliers

Cost Effectiveness
5 ppm NOx Limit
$17,000

Based on the reassessment, it is still cost-effective at $17,000 for the remaining units to achieve 5 ppmv. Staff maintained a BARCT limit of 5 ppmv for the SMR heater category and will include a conditional limit of 7.5 ppmv.

Steam Methane Reformer Heater with Integrated Gas Turbine

The SMR heater with an integrated gas turbine is a unique arrangement comprised of a gas turbine and an SMR heater that share a combined stack. Staff also consulted with Norton Engineering for recommendations on how to properly address this system. Norton Engineering recommended that due to the unique arrangement and configuration, it should be evaluated as a system in its own subcategory. The gas turbine is located upstream of the heater and under normal integrated operation, a portion of the gas turbine exhaust provides combustion air for the burners in the SMR heater, and the remaining turbine exhaust exits the combined stack. The unit currently has LNB and SCR for NOx controls and has a permit limit of 9 ppmv at 15%O_2. The BARCT assessment for the category was presented and discussed at Working Group Meeting #11 on May 21, 2020. The current emissions for the unit are less than 5 ppmv at 15% O_2 on an annual basis and in order to maintain a 5 ppmv staff concluded that the existing SCR can be upgraded to improve or maintain the NOx reduction efficiency. Since this system is also impacted by the operation of the gas turbine, staff evaluated the BARCT at 3 ppmv and 5 ppmv. Staff assumed the cost for an SCR upgrade to be 30 percent of a new SCR and O&M increase of 20% associated with the upgrade.

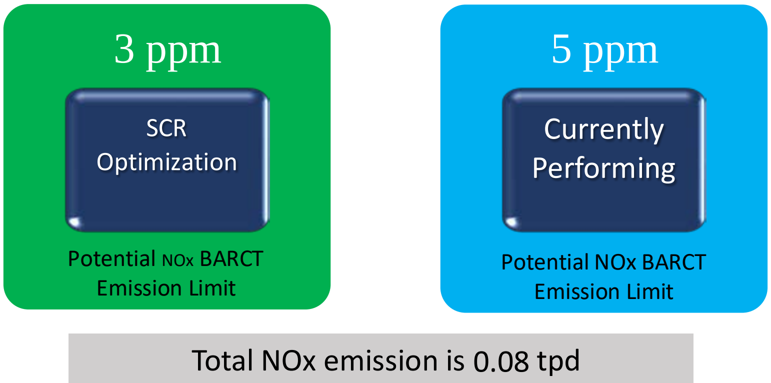


Figure B-13. Summary of BARCT Assessment

No other NOx limit was cost-effectiveness therefore staff did not calculate the incremental cost-effectiveness for this equipment category, so staff proposed a BARCT limit of 5 ppmv at 15% O_2 for SMR heater with gas turbine.

Table B-32. Cost Effectiveness for SMR Heaters with Gas Turbine

Cost Effectiveness		
Heater Category	3 ppm (SCR Upgrade)	5 ppm
SMR Heater with Gas Turbine	$69,054	Currently Performing

Startup Heaters

There are five heaters in this category and all heaters are associated with the FCCU. The startup air heaters are located within the FCC operating units and only used during startup of the FCC regenerator. The NOx emissions from these heaters exit the same stack as the FCC regenerator and since most of the FCCs already have a SCR, adding a second SCR is not feasible since the SCR will more than likely not reach optimal operating temperature for an extended period of time. Once the FCCU regenerator is up to operating temperature, these heaters are shut off and no longer used. Annual emissions from this category are 0.0029 tons per day based on 2017 annual emissions data. Staff estimated SCR cost for these startup air heaters using the revised U.S. EPA cost model and determined this category is not cost-effective at $1.7 MM per ton of NOx reduced. Staff proposes a low-use exemption of 200 hours per year for this category. No incremental cost-effectiveness was calculated as no additional NOx control technology was identified.

Sulfuric Acid Furnaces

There are two sulfuric acid plant furnaces in this category – one is an operating unit within a refinery and the other is a standalone plant. Both facilities regenerates spent sulfuric acid used in the refinery alkylation process where the main feedstock is spent sulfuric acid. Depending on the ratio of feedstock used at each facility, fuel gas demand will vary. The process and operation for both is similar and therefore NOx controls are similar. Staff presented the BARCT assessment for this category at Working Group Meeting #13 held on August 12, 2020 and a follow-up BARCT assessment at Working Group Meeting #15 on November 4, 2020. At WGM #13 staff evaluated the feasibility of several potential NOx control options which included LNB, SCR, and LoTOx™.

After meeting with the manufacturer and receiving estimates, staff conducted the cost effectiveness based on a potential BARCT limit of 20 ppmv and 2 ppmv.

Low-NOx Burners (LNB)

Each of the furnaces is equipped with two burners, but only one is equipped with LNB. LNBs for this application are specialized for high sulfur and high temperature applications. Both units operate at very high temperatures at 2,200 ºF, so LNB must be robust and engineered for the specific application. Based on vendor feedback, NOx reductions from LNBs are between 25% to 50% from traditional burners. Based on vendor feedback custom designed LNB will typically achieve between 25 to 30 ppmv. One facility provided staff with a cost estimate for LNBs installation at their facility which was approximately $4.5 MM and using the revised LNB cost-curve at approximately $3.2 MM. Based on the cost estimates, it was determined that LNBs at 20 ppm was cost-effective at $50,000 per ton of NOx.

Selective Catalytic Reduction (SCR)

For SCR, staff identified two potential locations in the production process where it can be installed, Upstream of the catalytic converter and downstream of the scrubber. For each location staff also identified several potential issues with SCR that may impact the feasibility and costs.

Upstream of catalytic converter	Downstream of scrubber
• Ammonia may adversley impact process and foul catalyst in converter • Major re-engineering and process modification required • Increases cost • Not preferred	• Low temperature • Flue gas reheating to 600 F, supplemental firing may be required • Potential impacts on SOx emission control needs to be considered

Figure B-14. Potential locations for installing SCR

SCR cost-effectiveness was based on SCR cost estimate using the revised U.S. EPA cost spreadsheet with the assumption of a downstream installation which will require flue gas reheating. Staff's calculated that a duct burner with a rated heat input of approximately 43 MMBtu/hour will be necessary to raise the flue gas temperature to 600 ºF. The additional cost was estimated as follows:

- $4 MM cost increase for the duct burner and larger SCR due to accommodate additional NOx reduction from burner
- Additional NOx increases of 0.25 tons per year
- Additional Natural gas cost to fuel duct burner at $1.79/MMBtu

Once all additional costs were incorporated, it was determined that it was not cost-effective for SCR at $68,000 per ton of NOx reduced.

Low Temperature Oxidation (LoTOx™) with Wet Gas Scrubber

Both sulfuric acid plants currently have a wet scrubber downstream of the process for SOx control. LoTOx™ is a potential technology that can be used since scrubber technology is currently being employed. The technology uses ozone injection in conjunction with a wet scrubber system to remove NOx in the flue gas. Ozone generation equipment is required on site and can be modulated on demand depending on the removal efficiency required. The annual operating cost for a LoTOx™ system is higher when compared to SCR and the facility may be required to upgrade their waste effluent treatment system to treat the wastewater generated. The advantage of the LoTOx™ system is that it is a multipollutant control system that can be used to control SOx in addition to NOx. One advantage of LoTOx™ over SCR is that LoTOx™ does not require a high operating temperature, optimal temperature range is 200ºF to 300ºF. Potential location for the system is after the absorber tower(s). LoTOx™ cost estimate based on vendor quote of $15 MM with annual operating cost of approximately $1 MM. It was determined that LoTOx™ was not cost-effective.

Table B-33. Cost Effectiveness for Sulfuric Acid Plant Furnaces

Cost Effectiveness			
Equipment	**2 ppm**		**20 ppm**
Sulfuric Acid Plant Furnaces	**SCR**	**LoTOx**	**LNB**
	$68,000	$92,000	$50,000

Based on the BARCT assessment staff concluded that the only cost-effective option is custom designed LNB. Staff initially proposed a 20 ppmv for the sulfuric acid furnace but was later revised to 30 ppmv based on the recommendation of Norton Engineering. Since both furnaces are operating at or below the 30 ppmv, staff does not anticipate any cost for the category.

Startup Heaters and boilers at Sulfuric Acid Plants

Each of the two Sulfuric acid plants have startup heaters which are used to heat up the catalytic converter during periods of unit startup. Once the catalytic converter is up to temperature, the heater is shut off. Only one facility has a startup boiler that is operated when the facility is down for maintenance – plant steam is generated through heat recovery from the furnace flue gas. The boiler is equipped with a LNB. All startup heaters and boilers are permitted for use during startup of the acid plant only and is limited on annual firing rates – 23,000 to 90,000 MMBtu per year. Total NOx emissions for this category is 0.0011 tons per day. Staff evaluated the cost-effectiveness of achieving 2 ppmv with SCR/LNB combination and 20 ppmv with new LNB.

Table B-34. Cost Effectiveness for Start-Ip Heaters and Boilers at Sulfuric Acid Plants

Cost Effectiveness		
Heater Category	2 ppm (LNB+SCR)	20 ppm (LNB)
Start-Up Heaters	$2.2 MM	$334,630
Start-Up Boilers	$3.3 MM	$4.8 MM

Either control options were determined to be not cost-effective, so staff proposed to allow a use exemption for the startup heaters and boilers and maintain current permit limit on firing rate per year. No incremental cost-effectiveness was calculated as there were no additional NOx control technologies identified.

Proposed BARCT Limits for the Heaters and Boilers Category

Process Heaters

Table B-35. Proposed BARCT Limits for Process Heaters

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Process Heaters (size in MMBtu/hour)							
<40	67	40/9	--	2 hours	0.49	0.031	$16,000/-[1]
≥40 - ≤110	67	5	18	24 hours	2.05	1.65	$50,500
>110	51	5	22	24 hours	2.52	1.58	$49,800

[1] Some additional costs incurred upon burner replacement.

Boilers

Table B-36. Proposed BARCT Limits for Boilers

Refinery Equipment Category(1)	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Boilers (size in MMBtu/hour)							
<40	5	40/5	--	2 hours	0.02	--	$-[1]
≥40 - ≤110	3	5	--	24 hours	0.052		$25,000
>110	20	5	7.5	24 hours	2.55	2.19	$11,000

[1] Some additional costs incurred upon burner replacement.

Steam Methane Reformer Heaters

Table B-37. Proposed BARCT Limits for Steam Methane Reformer Heaters

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
SMR Heaters							
All	11	5	7.5	24 hours	1.02	0.62	$17,000

Steam Methane Reformer Heater with Gas Turbine

Table B-38. Proposed BARCT Limits for Steam Methane Reformer Heater with Gas Turbine

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
SMR Heater & Gas Turbine							
All	2	5	--	24 hours	0.082	--	$0

Startup Heaters

Table B-39. Proposed BARCT Limits for Startup Heaters

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Startup Heaters (MMBtu/hour)							
≥40 - ≤110	2	Low-Use	--	--	0.002	--	$0
>110	3	Low-Use	--	--	0.0007	--	$0

Sulfuric Acid Furnace

Table B-40. Proposed BARCT Limits for Sulfuric Acid Furnace

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Sulfuric Acid Furnace							
Furnace	2	30	--	365 day	0.097	--	$0

Start-up Heaters and Boilers located at Sulfuric Acid Plants

Table B-41. Proposed BARCT Limits for Start-up Heaters and Boilers at Sulfuric Acid Plants

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Process Heaters (size in MMBtu/hour)							
<20	1	Low-Use	--	--	0.0002	--	$0
≥40 - ≤110	2	Low-Use	--	--	0.0009	--	$0

APPENDIX C PETROLEUM COKE CALCINER

Petroleum Coke Calciner

The Marathon (Tesoro Refinery) petroleum coke calciner is the only facility of its kind in the South Coast Air Basin and is currently operating within the NOx RECLAIM program. The BARCT assessment was initiated and presented in Working Group Meeting #2 on June 14, 2018 and completed and presented during Working Group Meeting #12 held on July 17, 2020.

Process Description

Coke calcining is a process that improves the quality and value of green petroleum coke, which is produced at petroleum refineries in the delayed coker unit. The Tesoro Calciner processes green petroleum coke produced by the nearby Tesoro Carson Refinery. The dried green petroleum coke is introduced into the high end of the rotary kiln, tumbled by rotation, and moved down the kiln countercurrent to a hot stream of combustion air to drive off the moisture, impurities, and hydrocarbons. After discharging from the kiln, the calcined petroleum coke drops into a cooling chamber, where it is quenched with water, treated with dedusting agents for dust control, and carried by conveyors to storage silos. The calcined coke product is sold to various industries such as the aluminum, steel, specialty chemical, and cement industry and is also sold and used as fuel.

A simplified process diagram of the coke calcining process is shown in the figure below1. Green petroleum coke is fed to the 120 MMBtu per hour rotary kiln which has a combination burner capable of firing natural gas and diesel fuel to combust volatile hydrocarbons and an oxygen injection system for additional control of VOC and CO emissions. The residence time in the rotary kiln is approximately one hour. Exhaust gases from the kiln enters the 130 MMBtu per hour pyroscrubber afterburner where entrained particulates, residual VOCs, and other combustible gases, including CO, are oxidized. Once treated in the primary dust collector (C66), dust-laden air from the coke cooler is also fed to pyroscrubber afterburner for combusting volatile hydrocarbons. The temperature in the pyroscrubber is maintained at 2,200°F or greater as required by permit condition. The hot gases from the pyroscrubber then pass through the waste heat recovery boiler (D104) to generate steam which is used for electrical power generation. The gases leave the waste heat recovery boiler at 450°F and continue to the lime scrubber spray chamber reactor (C68) where lime slurry is introduced to the gas stream via an atomizer which generates liquid droplets. The lime slurry droplets react with the SOx in the flue gas to form calcium sulfates and calcium sulfites to reduce SOx emissions. The gases leave the spray dryer at approximately 210°F and is routed to the main baghouse (C69) which consists of 12 modules. Each module contains 1,689 Teflon-coated fiberglass bags, 8 inches in diameter and 26 feet in length to control PM emissions. A bag leak detection system monitors relative changes of PM emissions in each module and differential pressure across the baghouse. The gas is drawn through the baghouse by an induced draft fan and is discharged to the atmosphere through the main stack (S71). NOx controls could be installed at several places in the process (highlighted with numbers 1 – 4 on Figure 1). These locations are compared in this analysis with respect to the effectiveness of different NOx control technologies.

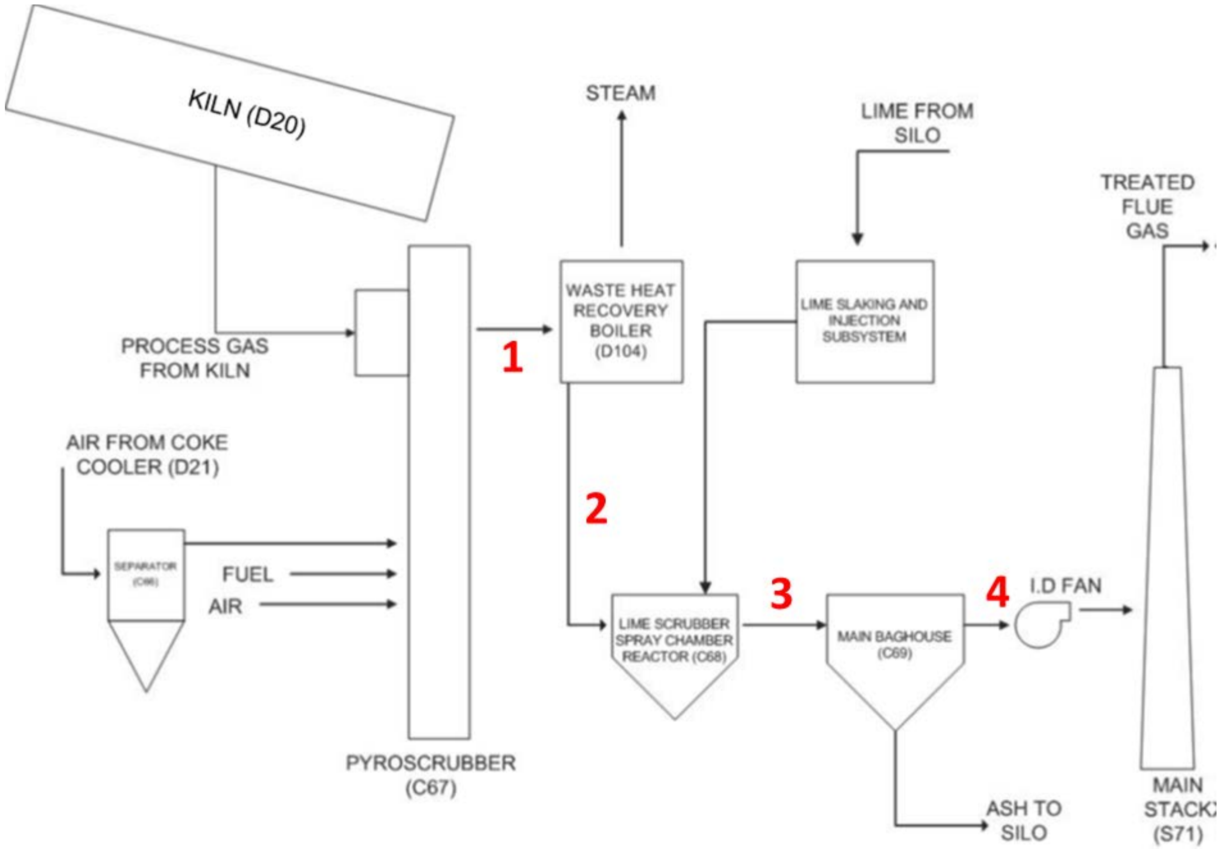


Figure C-1. Coke Calciner Process and Potential Locations for NOx Control (Numbered in Red)

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

There are no specific South Coast AQMD regulatory requirements for petroleum calciner beyond the requirements in RECLAIM. BARCT assessments were conducted in 2005 and 2015 as part of the RECLAIM program which established a NOx permit limit equivalency of 30 ppmv and 10 ppmv, respectively (see table below). For *non-refinery* kiln/calciners, such as cement kilns, Rule 1147 – *NOx Reductions from Miscellaneous Sources* established a 60 ppmv NOx limit. The process and operation of cement kilns is similar to that of the petroleum coke calciner, but the feedstock is different.

Table C-1. South Coast AQMD Rules NOx Limits

Refinery Rule Limits and Assessments		
	2005 RECLAIM BARCT	2015 RECLAIM BARCT
Petroleum Refining, Calciner	30 ppmv	10 ppmv
Non-Refinery Rule Limits		
Rule 1147 – NOx Reductions from Miscellaneous Sources		
Calciner and Kiln (≥1200°F)	60 ppmv at 3% O_2, dry or 0.073 lb/MMBtu	

Assessment of Emission Limits of Existing Units

The Marathon (Tesoro Refinery) calciner is regulated under RECLAIM, which is a mass emission-based program, so no NOx concentration permit limits were established for the kiln and pyroscrubber. Staff did not identify any petroleum coke calciners currently equipped with NOx control equipment at petroleum crude refineries but did identify similar rotary kiln processes used in the cement and lime industry. BP Cherry Point refinery in Blaine, Washington has a coke calcining operation that uses three calciner hearths rather than a kiln process. The hearths are equipped with caustic scrubbers and a wet electrostatic precipitator for PM and sulfuric acid control, but no NOx controls. The coke calciner the single largest source of NOx emissions in the PR 1109.1 universe.

Staff assessed the emissions limits of existing units, in the case of the petroleum coke calciner, there is only one unit to assess. Based on NOx survey questionnaire, Marathon (Tesoro Refinery) operates one coke calciner that has two connected combustion devices, a rotary kiln and pyroscrubber that share a common stack equipped with a single CEMS. There are no existing NOx controls, but the equipment has controls for SOx and PM. The 2017 NOx emissions from the coke calciner and current NOx outlet concentration are listed in the following table.

Table C-2. 2017 NOx Emissions for Coke Calciner

Equipment	2017 NOx Emissions (lbs)	Outlet NOx (ppmv) @ 3% O_2
Rotary Kiln	521,986	65 to 85
Pyroscrubber		
Total (tpd)	**0.71**	

Assessment of Other Districts NOx Rules and Limits

Staff assessed other rules and regulations outside the South Coast jurisdiction that regulate sources similar to a petroleum coke calciner, which is summarized in the following table.

Table C-3. Non-South Coast AQMD Rules NOx Limits

San Joaquin Valley Air Pollution Control District		
Rule 4313 – Lime Kilns		
Fuel Type	**NOx Limit (ppmv*) at 3% O_2, dry**	**NOx Limit (lb/MMBtu)**
Gaseous Fuel	82.6	0.10
Distillate Fuel Oil	93.72	0.12
Residual Fuel Oil	165.2	0.20
*** Converted ppmv emissions**		

Texas Commission on Environmental Quality	
Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	
Kiln Type	**NOx Limit**
Lime Kilns	0.66 lb per ton of calcium oxide
Lightweight Aggregate Kilns	1.25 lb per ton of product

Assessment of Pollution Control Technologies

There are several unique challenges to the coke calciner, including the impacts from controlling other pollutants, such as Sox and PM, and the high operating temperature required to achieve VOC destruction. Due to the high operating temperature requirements, combustion modifications, such as LNBs, will not provide significant NOx reductions. Staff explored three feasible NOx control technologies: SCR, LoTOx™, and UltraCat™, which are all capable of achieving greater than 95 percent. LoTOx™ and UltraCat™ are both multi-pollutant control technologies so they may be able to replace existing SOx and PM controls.

The two categories of NOx controls are combustion modifications and flue gas treatment techniques. Staff evaluated both combustion modification and flue gas treatment techniques for the coke calciner and determined flue gas treatment techniques are the most effective form of NOx control in terms of emission reductions. Combustion modification controls, such as the current low NOx burner technology, may not be feasible due to operational constraints, and would not result in significant NOx reductions. There are two burner systems used in the coke calcining process. The first is used to heat the green coke in rotary kiln and is rated at 120 MMBtu per hour and can fire on either natural gas or diesel fuel. This burner is designed to operate close to stoichiometric combustion to minimize the oxygen content of the products of combustion to prevent possible undesirable ignition of the coke material. Traditional low NOx burners utilize additional excess air or staged combustion, which would not work for the coke calciner due to the introduction of excess oxygen into the kiln. The second burner system is used in the pyroscrubber. It is rated at 130 MMBtu per hour and can also fire on natural gas or diesel fuel. The function of this burner is to preheat the pyroscrubber prior to start of the kiln. Once the kiln is in full operation, the heat release from the incineration of VOCs and coke dust entering the pyroscrubber provides enough energy to allow the startup burners to be turned down or shut off completely. The burners can potentially be upgraded to a low NOx design, but they only run for a short period of time at startup and only contribute a small percentage of the overall NOx emissions. Performing an emissions balance of the coke calciner shows that fuel combustion from the burners contributes approximately 8 tons (4 percent) to the total yearly NOx emissions. The primary source of NOx emissions in the pyroscrubber is from combustion of the VOCs and coke particulates; thus, the most effective NOx control is flue gas treatment. Ideally, the NOx control device should be located either downstream of waste heat boiler or baghouse due to the high flue gas temperatures coming off the pyroscrubber. Locations for potential flue gas treatment NOx control are shown in Figure C-1 and listed in the table below.

Table C-4. Potential Locations for Flue Gas NOx Treatment

Location Number	Description
Location 1	Pyroscrubber to Waste Heat Boiler
Location 2	Waste Heat Boiler to Lime Scrubber
Location 3	Lime Scrubber to Baghouse
Location 4	Baghouse to Main Stack

Based on staff's assessment of control technologies, commercially available flue gas treatment NOx control technologies for the coke calciner are LoTOx™, SCR, and UltraCat™. LoTOx™ and UltraCat™ are commercially available multi-pollutant control technologies that can operate at low temperatures in the removal of NOx, SOx, and PM.

LoTOx™ with Wet Gas Scrubber

For the LoTOx™ application at the coke calciner, staff identified location 2 as the ideal location for the technology, but the temperature of 450°F out of the waste heat boiler will be an issue. As mentioned in the discussion on LoTOx™ control technology, the process requires ozone in order to convert the NOx into water soluble N_2O_5. The LoTOx™ technology has an upper temperature limit of 300°F for the flue gas temperature into the scrubber due to the half-life decay of ozone back to oxygen. In order to overcome this issue, a considerable amount of oxygen will be required at temperatures greater than 300°F. BELCO will typically recommend a water quench step to reduce the temperature below the 300°F, thus location 2 at the coke calciner will require a quench system in addition to the LoTOx™ system.

Selective Catalytic Reduction

If a SCR is used to reduce NOx emissions in the coke calciner, the location for the SCR needs to be considered. Staff identified four potential locations which consider temperature, coke dust/particulate loading, catalyst type, and whether flue gas reheating will be required. Most SCR catalyst manufacturers typically avoid "dirty" or high particulate/dust systems to reduce the risk for catalyst plugging. In addition, petroleum coke dust contains metals such as sodium, nickel, and vanadium; vanadium which will deactivate the catalyst and lower its activity. Flue gas temperature is also a critical factor in achieve optimum NOx removal and temperatures in the calciner ranges from 2,200°F to 200°F, so flue gas reheating may be required depending on location. However, the new generation of low temperature catalyst does increase the potential locations for the SCR without the need for much flue gas reheating. A vertical down flow SCR system is also recommended to help reduce overall footprint and layout. Based on these considerations, staff concluded that Location 4 is the most suitable location for an SCR application based on the criteria in the following table.

Table C-5. Assessment of Ideal Location for an SCR Application

	Location 1	Location 2	Location 3	Location 4
	Pyroscrubber to waste heat boiler	Waste heat boiler to lime scrubber	Lime scrubber to baghouse	Baghouse to main stack
Appropriate Temperature	No	Yes	No	No
Particulate/dust Plugging of Catalyst	Yes	Yes	Yes	No
Potential for Metal Deactivation	Yes	Yes	No	No
Flue Gas Reheating Required	No	No	Yes	Yes
Potential Location of NOx Control	No	No	No	Yes

Location 1: The temperature at this location can be as high as 2,200°F which is beyond the effective temperature range for most SCR catalyst operation. The location also has the potential for coke particulate plugging. Location 1 is not ideal for SCR installation and not recommended.

Location 2: The temperature is approximately 450°F and is ideal for a low temperature catalyst but has the potential for catalyst plugging due to coke particulates/dust from the process. An assessment of the particle size distribution and solids loading should be performed to further evaluate feasibility. The SO_3 levels at this location is also not known and may present an issue with ammonium bisulfate formation which may deactivate the catalyst. Location 2 is also not ideal for SCR installation and not recommended.

Location 3**:** The temperature at this location is approximately 200°F and will require flue gas reheating. This location also has the potential for catalyst plugging due to the dry lime sorbent injection located just upstream. Most SCR vendors typically will recommend avoiding "dirty" or high particulate systems if possible, so this location is also not an ideal location and not recommended.

Location 4: Similar to Location 3, the temperature is approximately 200°F and is too low to get meaningful NOx reductions, even with a low temperature catalyst. The flue gas temperature would need to be increased to at least 400°F at the face of the catalyst for proper catalyst operation, preferably at 450°F to reduce the potential for ammonium bisulfate formation. Flue gas reheating can be accomplished with a duct burner, heating element, or some other method to raise flue gas temperature, such as adjustments to the waste heat recovery boiler to send more heat to the baghouse. Adjustments to the waste heat recovery boiler would reduce steam production but would be more cost effective than installing an afterburner system to reheat the flue gas. Typical Teflon-coated fiberglass bags in the baghouse can withstand temperatures up to 500°F. This location is also the "cleanest" compared to the other locations because the baghouse filters a majority of the PM. Placing the SCR downstream of the induced draft fan and the ammonia injection upstream of the induced draft fan can aide in uniform mixing of NOx and ammonia to increase removal efficiency and may be the most suitable location for a SCR with low temperature catalyst.

Initial BARCT Assessment and Considerations

Based on the annual average NOx emissions of 64 to 85 ppmv in the flue gas and 95% NOx emission reductions potential of the control technology assessed, staff determined a 5 ppmv NOx limit is technically feasible.

Costs and Cost-Effectiveness Analysis

LoTOx™ with Scrubber Costs

Tesoro provided cost estimates for total install cost of the LoTOx™ system at $117 million. Details of cost includes labor, downstream waste effluent treatment system, ozone generation system, water supply system, control systems, electrical, civil, mechanical, and structural work necessary to support the LoTOx™ installation. Estimates from the manufacturer were approximately $12 million and annual operating cost of $600,000. The manufacturer also estimates a 10% increase in water usage for the LoTOx™ system. Staff estimated installation costs to be 4.5 times ($54 million) of the capital cost based on the recommendation by Norton Engineering Consultants (NEC) in the 2015 BARCT assessment. Staff estimated the total installed cost for the LoTOx™ system to be $66 million. However, staff's estimates did not include a waste effluent treatment system. Staff's assumption that Tesoro's estimate includes all necessary costs for the LoTOx™ installation, so Tesoro's provided total installed cost estimate of $117 million and annual operating cost of $1.4 million was used to determine cost effectiveness.

UltraCat™ Costs

Tesoro provided process parameters to Tri-Mer, the manufacturer of UltraCat™, Tri-Mer assessed the information provided and estimated the capital cost for the UltraCat™ system to be $8.2 million with a total installed cost of approximately $50 million dollars. Tri-Mer estimated the annual operating cost to be approximately $2 million. The cost provided by the manufacturer includes any electrical expansion required by the project to accommodate the new UltraCat™ system. Staff estimated installation cost to be 4.5 times ($36.9 million) of the capital cost based on the recommendation by Norton Engineering in the 2015 BARCT assessment. The total installed cost is estimated to be $45.1 million; staff also applied a contingency factor of 1.2 to the present worth value to account for labor rates in California. Staff's estimation is within range of Tri-Mer's quoted total installed cost of approximately $50 Million.

SCR Costs

Cost estimates for SCR systems provided by vendors and range anywhere from $5 million to $8 million based on a five-year catalyst life, not including installation costs. The quotes provided from vendors are generalized estimates which may not reflect California structural codes or site-specific constraints of the facility. Staff estimated capital installation cost to be 4.5 times ($36 million) of the capital cost based on the recommendation by Norton Engineering in the 2015 BARCT assessment. Staff's estimate for total installed cost to be $44 million and applied a contingency factor of 1.2 to the present worth value to account for labor rates in California. During our initial meeting on September 28, 2018, the facility stated that they explored NOx control options and estimates for a SCR system were approximately $60 million due to the complexity and space restraints. Staff estimated annual operating cost to be $458,000, based on the annual operating costs reported in the survey for a SCR installed on a gas turbine. Gas turbine was chosen because flue gas flow rate is similar to that of the calciner. Staff also included the additional cost required to fuel the duct burner that will heat the flue gas to the appropriate temperature for the low-temperature catalysts and the total annual operating cost considering the added fuel cost, as tabulated in the following tables.

Table C-6. Estimated Cost for Additional Annual Fuel Cost

Estimated Additional Annual Fuel Cost	
Duct Burner fuel consumption	4,000 MMscf/year
Natural Gas cost in California	$7,600/MMscf
Total Fuel Cost	$4000 × 7,600 = $30,400

Table C-7. Estimated Annual Operating Cost of Duct Burner

Annual Operating Cost Reported for Turbine SCR	Estimated Additional Annual Fuel Cost	Estimated Annual Operating Cost
$427,000	$30,400	$458,000

The emission reductions for each of the three technologies is estimated to be 0.68 tons per day of NOx reduced based on representative year 2017 as reported by the facility. The table below summaries the cost and cost-effectiveness of each technology.

Table C-8. Cost and Cost-effectiveness Summary

Staff Cost Estimates			
Control Technology	LoTOx™	UltraCat™	SCR
Capital Costs (1)	$12,000,000	$8,200,000	$8,000,000
Installation Costs (2)	$54,000,000	$36,900,000	$36,000,000
Total Installed Cost	$66,000,000	$45,100,000	$44,000,000
Annual Operating Cost	$600,000	$2,000,000	$458,000[6]
PWV (3)	$75,373,248	$76,344,160	$51,154,913
Contingency Factor (4)	1.2	1.2	1.2
PWV with contingency factor	$90,447,897	$91,612,992	$61,385,895
Cost Effectiveness (5)	**$15,000**	**$15,000**	**$10,000**
Facility Cost Estimates			
Total Installed Cost	$117,000,000	–	$60,000,000
Annual Operating Cost	$1,354,625	–	$458,000
PWV (3)	$138,162,060	–	$67,154,913
Contingency Factor	Included in estimate	–	Included in estimate
Cost Effectiveness (5)	**$22,000**	–	**$11,000**

(1) Equipment cost estimation provided to staff by technology manufacturer. Cost in 2018-dollar year.
(2) Assumed installation cost to be 4.5 times capital cost based off Norton Engineering’s recommendation in 2015 BARCT assessment at facility due to space constraints.
(3) PWV = Capital Costs + (15.62×Annual Operating Cost)
(4) Contingency factor to account for Senate Bill 54 requiring California refineries to hire unionized labor.
(5) Cost Effectiveness calculated using 25-year life
(6) Estimation based on annual operating cost of SCR for gas turbine and includes cost of supplemental fuel required to reheat flue gas if required (~4,000 MMSCF/year at $7,600/MMscf)

Proposed BARCT Limits

After consulting with the NOx control technology manufacturers, reviewing facility data, and considering challenges and costs for implementing the technology, South Coast AQMD staff concludes 5 ppmv NOx concentration is technically feasible at the stack. The outlet NOx is approximately 64 to 85 ppmv (annual average from survey data) and the control technologies can achieve 95 percent NOx reduction leaving approximately 3.2 - 4.25 ppmv NOx remaining. Staff recommends setting the BARCT level to a long-term limit of 5 ppmv NOx at three percent oxygen with a 365-day rolling averaging time. Staff recommends the long-term averaging time due to specific challenges at the coke calciner including, NOx emissions are feed dependent and variable; the coke calciner is a process unit and not an individual piece of combustion equipment; if a NOx excursion were to occur and an operational adjustment made, the response time may not be seen for several hours; and multiple pollutants need to also be addressed. To ensure short-term NOx limits also remain low, staff is also proposing a short-term limit of 10 ppmv at three percent oxygen with a 7-day rolling average. This short-term limit will account for process variations in day-to-day operation of the coke calciner. NOx control technologies such as LoTOx™, SCR, and UltraCat™ are commercially available and it is technically feasible and cost-effective to achieve the proposed levels. The following table summarizes the proposed BARCT NOx limits for the coke calciner. Post-combustion control was the only NOx control technology identified, so an incremental cost-effectiveness was not calculated as all three options are cost-effective to reach the same BARCT NOx limit.

Table C-9. Proposed BARCT Limits

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions (tpd)
Coke Calciner	5	365 day	LoTOx™, SCR, UltraCat™	$10,000 – $23,000	0.68
	10	7 day			

APPENDIX D FLUID CATALYTIC CRACKING UNITS

Fluid Catalytic Cracking Units

There are five petroleum crude refineries that operate five FCCUs in the South Coast AQMD: TORC, Chevron, Tesoro, Phillips 66, and Ultramar. The initial BARCT Assessment was presented in Working Group Meeting #2 on June 14, 2018 and completed and presented during Working Group Meeting #11 held on May 21, 2020. A reassessment to address units with existing controls and outliers was presented at Working Group Meeting #21. The reassessment was based on facility revised cost data. A brief description of the process is presented below.

Process Description

An FCCU converts heavy gas oils from the distillation process into more valuable gasoline and lighter products. A schematic of the process is shown in Figure 1. The process uses a very fine catalyst that behaves as a fluid when aerated. The fluidized catalyst is circulated continuously between a cracking reactor and a catalyst regenerator which transfers heat from the regenerator to the incoming feed going in the reactor. The cracking reaction is endothermic, and the regeneration reaction is exothermic. The fresh gas oil feed is preheated by heat exchangers to a temperature range of 500°–800°F and enters the FCCU at the base of the feed riser where it is contacted with the hot regenerated catalyst along with injected steam. The heat from the catalyst vaporizes the feed and raises it to the desired reaction temperature. The mixture of catalyst and hydrocarbon vapor travels up the riser into the reactor. The cracking reaction starts in the feed riser and continues in the reactor. Average reactor temperatures are in the range of 900°–1,000°F. As the cracking reaction progresses, the catalyst surface is gradually coated with coke, which deactivates the catalyst and reduces its efficiency. The cracked hydrocarbon vapors are routed overhead to a distillation column for separation into various products, the oil remaining on the catalyst is removed by steam stripping before the spent catalyst is cycled back into the regenerator.

In the regenerator, spent catalyst is reactivated (regenerated) by burning the coke off the catalyst surface. The regenerated catalyst is generally steam-stripped to remove adsorbed oxygen before being cycled back to the reactor. The regenerator exit temperatures for catalyst are about 1,200°–1,450°F. The regenerator can be designed and operated to either partially burn the coke on the catalyst to a mixture of carbon monoxide (CO) and carbon dioxide (CO_2), or completely burn the coke to CO_2. The regenerator temperature is carefully controlled to prevent catalyst deactivation by overheating and to provide the desired amount of carbon burn-off. This is done by controlling the air flow to give a desired CO_2/CO ratio in the exit flue gases or the desired temperature in the regenerator. The flue gas containing a high level of CO is routed to a supplemental fuel fired CO boiler if needed to completely burn off the CO to CO_2. All FCCUs in the South Coast AQMD are currently operated in complete burn mode; only two of the FCCUs have CO boilers and are used as waste heat recovery devices without any supplemental fuel. However, the CO boilers are equipped with low NOx burners capable of supplemental firing on refinery gas or natural gas.

The FCCU is a major source of SOx, NOx, PM_{10}, $PM_{2.5}$, as well as ammonia (NH_3), hydrogen cyanide (HCN) and other pollutants in the refinery and are formed during the regeneration cycle. PM is formed when some of the catalyst is lost in the form of catalyst fines. Approximately 90 percent of the NOx generated from the FCCUs are from the nitrogen in the feed that is accumulated in the coke which is burned-off in the regenerator. This portion of the NOx is called “fuel” NOx. “Fuel” NOx is a combination of nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The remaining 10 percent of the NOx generated from the FCCUs are “thermal” NOx which is generated in the high temperature zones in the regenerator, and “prompt” NOx generated from the reaction between nitrogen and oxygen in the combustion air. The NOx emissions from the FCCU are typically controlled with DeNOx additives, selective catalytic reduction (SCR), and LoTOx™ scrubbers.

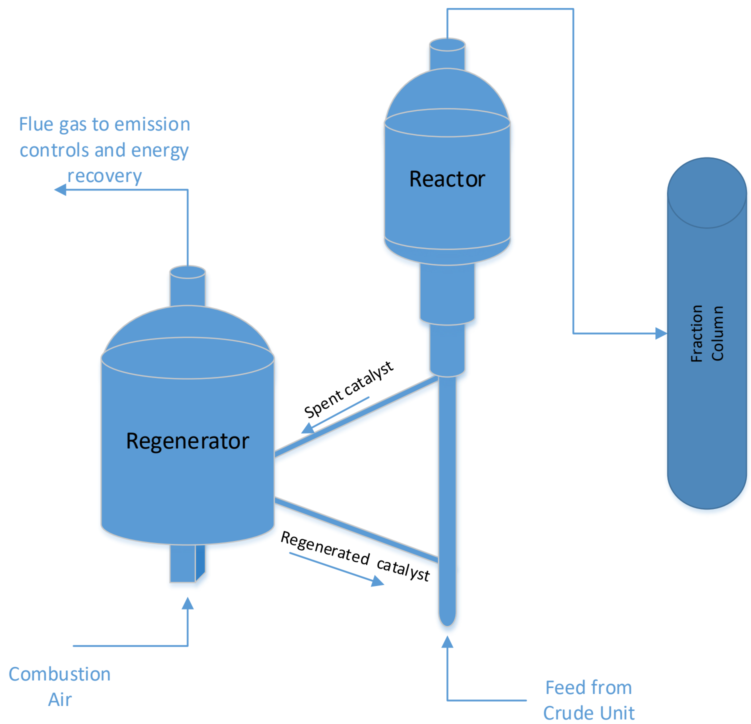


Figure D-1. Simplified Schematic of FCCU Process

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Table D-1. South Coast AQMD Rules NOx Limits

Refinery Rule Limits and Assessments		
	2005 RECLAIM BARCT	2015 RECLAIM BARCT
Petroleum Refining, FCCU	85% reduction for FCCU and CO Boiler	2 ppmv at 3% O_2, dry

Assessment of Emission Limits of Existing Units

As shown in the table below, the total NOx emissions from the five FCCUs located in the South Coast AQMD are 0.83 tons per day.

Table D-2. 2017 NOx Emissions for FCCUs

Unit	Number of Units	2017 NOx Emissions (tpd)	Outlet NOx at 3% O_2 (ppmv)
FCCU	5	0.83	1.2 to 32.4

All five FCCUs operate below 40 ppmv NOx on annual basis. Ammonia limits on permit are 10 ppmv. Three FCCUs currently have SCRs in operation since 2000, 2003, and 2008. For these three FCCUs with SCRs, the outlet NOx concentrations range from 1.23 to 10.34 ppmv. One of the FCCU currently operates at a level under 2 ppmv NOx (as per permit conditions) on annual basis. As demonstrated FCCU's SCR, 2 ppmv NOx is a level of achieved-in-practice. At normal operations, the inlet NOx concentrations to the SCR range from 40 to 80 ppmv, and the outlet NOx concentrations are typically below 2 ppmv. The SCR can have three catalyst layers, but only two layers are in operation and still achieve 95 percent control efficiency. Typical catalyst life for this FCCU is approximately 5 to 6 years per SCR catalyst vendors. However, SCR catalysts could be replaced at much longer time intervals, such as 15 years or more. The other two FCCUs currently operate with no NOx controls and permit limits vary from 40 to 89 ppmv NOx. The outlet NOx concentrations are 14 to 32 ppmv.

Assessment of Other Districts NOx Rules and Limits

Staff assessed other rules and regulations outside the South Coast jurisdiction that regulate sources similar to FCCUs, which is summarized in the following table.

Table D-3. Other Air Districts NOx Rules and Limits for FCCUs

Bay Area Air Quality Management District	
Regulation 9-10-307 – Refinery NOx Emission Limit for CO Boilers	
NOx Limit – Operating Day	**NOx Limit – Calendar Year**
125 ppmv at 3% O_2, dry	85 ppmv at 3% O_2, dry
Texas Commission on Environmental Quality	
Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	
Description	**NOx Emission Limit (one of the following)**
FCCU (including CO boilers, CO furnaces, and catalyst regenerator vents)	40 ppmv at 0% O_2, dry basis
	90% NOx reduction of the exhaust concentration used to calculate the daily NOx emissions

Assessment of Pollution Control Technologies

Several commercial NOx control technologies for FCCUs are available including DeNOx, SCR, and LoTOx™ with wet scrubber. The most effective form of NOx control for FCCUs are post-combustion control technologies which can achieve up to 95 percent NOx reductions.

DeNOx Additive or Combustion Promoter

DeNOx is added to the regenerator as part of the catalyst blend and can reduce NOx up to 45 percent. The reduction efficiency is dependent on the configuration and design of the FCCU and the need for combustion promotion. Some refiners require an additive in the circulating catalyst inventory that will promote the combustion of CO in the dense phase of the regenerator bed to avoid "after burn". Traditional CO combustion promoter are Platinum-based that have an unwanted side effect of producing more NOx. DeNOx additives are non-platinum-based combustion promoters that raise the NOx levels less that platinum-based promoters or without promoters.

LoTOx™

LoTOx™ with wet gas scrubber (WGS) is a is post-combustion control technology that utilizes ozone with a wet gas scrubber to remove NOx and other pollutants, such as SOx and PM. The advantage of the LoTOx™ system is the multipollutant emission reductions that can be utilized at locations where space is an issue. A potential drawback of LoTOx™ is the maximum operating temperature of 325°F. FCCU regenerator flue gas temperatures are over 1,200°F; therefore, , a quench system will be required upstream of the LoTOx™ system to lower the flue gas temperature.

SCR

SCR is another flue gas treatment option that can achieve up to 95 percent NOx reduction. Three FCCUs within the South Coast AQMD use SCR for NOx control, one is performing at 2 ppmv at 3% O_2 based on a 365-day average, the other two are performing below 10 ppmv at 3% O_2 based on a 365-day average. SCR is proven NOx reduction technical for FCCUs. One FCCU in the South Coast AQMD is achieving the NOx limit of 2 ppmv with a SCR and another facility is in the process of constructing an SCR for a FCCU to meet the proposed 2 ppmv NOx limit.

Initial BARCT Assessment and Considerations

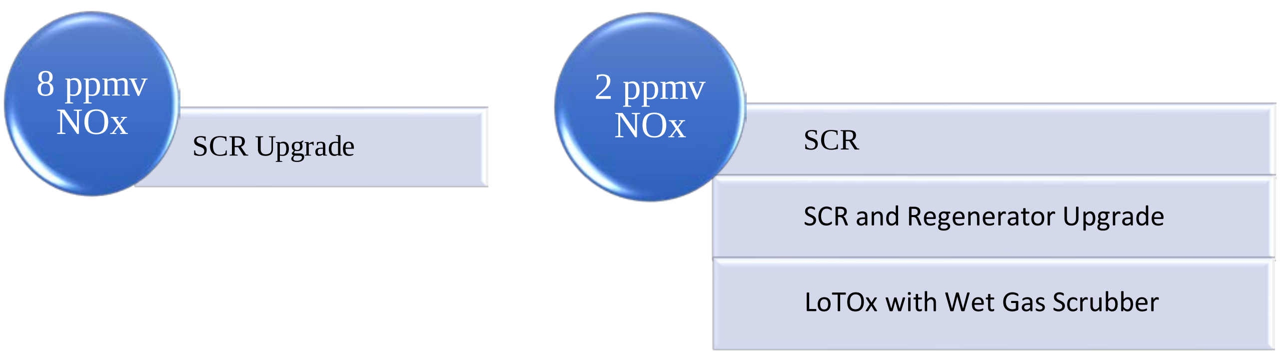
Based on the current performance of FCCUs with existing SCRs, reviewing current emission levels of existing FCCUs, and consulting with the NOx control technology manufacturers, staff concludes that a BARCT NOx limit of 2 ppmv at 3% O_2 NOx BARCT is technically feasible.

Costs and Cost-Effectiveness Analysis

Staff evaluated cost-effectiveness for all FCCUs that are not achieving the proposed 2 ppmv NOx limit. Facilities initially provided two capital cost estimates, $57 million and $19.5 million, that were used in the Total Installed Cost (TIC) estimation back in 2018. With these two data points, staff estimated costs for other units by scaling up the cost based on the flow rate. Annual average operating and maintenance cost (AC) was estimated based on the annual average catalyst replacement cost that facilities provided in the survey. The estimated AC is about 0.3 percent of the TIC for a new SCR installation. From there, staff assumed AC to be 0.5 percent of the TIC estimates for the control device, which is consistent with the boilers and heaters annual operating cost estimates. Staff used the Discounted Cash Flow (DCF) method using a 25-year equipment life and a four percent interest rate. The cost-effectiveness estimated at 2 ppmv NOx is $37,000 per ton of NOx reduced with a potential NOx reduction of 0.67 tons per day. In March 2021, staff allowed facilities to submit revised cost estimates based on refined engineering cost evaluations for their respective FCCUs. One refinery provided a cost estimate for a LoTOx™ system to achieve the proposed 2 ppmv NOx limit at a cost of $220 MM. two facilities provided revised cost of $1MM and $3MM for SCR upgrades to achieve 8 ppmv due to technical feasibility issues of achieving the proposed BARCT of 2 ppmv. One facility stated that they would have to replace their entire FCC regenerator along with a brand-new SCR at a cost of over $200MM to achieve the proposed BARCT limit of 2 ppmv.

Proposed BARCT Limits

Refinery stakeholders raised a concern over the technical feasibility and cost effectiveness for units with existing SCRs and their ability to achieve proposed BARCT limit of 2 ppmv. Initially staff assumed that those FCCUs with existing SCRS would only require an SCR upgrade to meet the proposed BARCT limit of 2 ppmv. Two refineries stated that based on further engineering evaluation, it is not technologically feasible to upgrade their existing SCRs to achieve less than 5 ppmv. In order to achieve the 2-ppmv, a brand-new SCR will need to be installed which would require demolition of the existing SCR, major reconfiguration, re-engineering, and re-design of the existing unit. In addition, major infrastructure modifications to the unit will be needed to accommodate the brand-new SCRs. Cost to replace the SCR are substantially higher than an upgrade and thus it is more cost-effective and feasible to upgrade existing units to achieve 8 ppmv NOx. Based on the revised cost and information from the refineries, staff reassessed the cost-effectiveness for FCCUs to meet 2 ppmv and 8 ppmv. In this category, two units are without NOx controls, one unit is in process of installing a SCR designed for 2 ppmv, three units with NOx controls, one unit performing well below 2 ppmv (annual average). Two units with SCR would need SCR replacement and new regenerator to achieve 2 ppmv and upgrades to existing SCR to achieve 8 ppmv. 8 ppmv will impact two refineries with existing SCRs and 2 ppmv will impact two refineries without any NOx controls – one refinery is currently in the process of constructing a SCR that is designed to achieve and meet the proposed BARCT of 2 ppmv.



Since some facilities did not provide costs for a brand-new SCR installation, staff estimated SCR total installed costs (TIC) based on vendor quote for a similar sized FCCU at a refinery. To estimate SCR cost, staff also applied the following:

- Increased cost by a factor of 4.5 for installation costs
- Increased cost by 20% to account for SB54 (requires refineries to hire unionized labor)
- Included 2 times retrofit factor to address space constraints -maximum multiplier in U.S. EPA cost model

FCCU Category Cost estimates

As mentioned earlier, one refinery provided cost for LoTOx™ system that can achieve multi-pollutant emission reductions (NOx, SOx, and PM) which costs considerably more than a SCR system. Since only NOx reductions of the three pollutants are required for 1109.1, staff evaluated LoTOx™ in achieving both NOx and SOx reductions and SCR for NOx reductions only. Below is the cost-effective analysis for the one refinery and potential control option pathways that they may choose.

Table D-4. Cost Effectiveness for FCCU

	Multi-Pollutant Scrubber	SCR
Estimated Present Worth Value	$218 MM	$76 MM
Emission Reductions (Lifetime tons)	NOx: 2,071	NOx: 2,071
	SOx: 2,027	
Cost Effectiveness	$46,000	$24,000

Based on the cost provided by the facilities, the LoTOx™ system is cost-effective at $46,000 if the facility choses it as a control option to meet the proposed BARCT limit of 2 ppmv.

Based on the revised cost data staff received from the refineries, 2 ppmv is not cost effective for all units in the FCCU category due to the high-cost effectiveness of two units currently equipped with NOx control. These two units have high cost to replace the existing control or modify the existing FCCU to achieve 2 ppmv. In addition, these two units are considered cost outliers due to the high cost and low emission reductions associated with achieving 2 ppmv from current operating levels. These two outlier units are currently performing near or below 10 ppmv based on a 365-day average. However, it is cost-effective for these outliers to upgrade or improve efficiency to achieve 8 ppmv. For units without any existing NOx control, it is cost-effective to add NOx controls to achieve 2 ppmv. In addition, the proposed rule will allow a 365-day rolling average to ensure the low levels can be met even with some operating variability.

Staff reassessed:

- The cost-effectiveness and incremental cost-effectiveness of the two cost outlier units for achieving a conditional limit at 8 ppmv and BARCT limit of 2 ppmv
- The cost-effectiveness of the remaining two units with the outlier units removed to achieve 2 ppmv

The table below provides cost-effectiveness for the FCCU category. Cost-effectiveness of SCR upgrades for units with existing SCRs (outliers) was calculated, then cost-effective for all FCCs were calculated along with the incremental cost-effectiveness. Finally, cost-effectiveness for units without existing controls were calculated. An incremental cost-effectiveness was not conducted for units without existing controls because no other control technology was identified.

Table D-5. Proposed BARCT Limits and Cost-Effectiveness

NOx Limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost-Effectiveness ($/ton NOx Removed)	Emission Reductions (tpd)
FCCUs with Existing SCRs (Outliers)				
8	365 day	SCR Upgrades	$12,000	0.06
10	7 day			
All FCCUs Including Outliers				
2	365 day	New SCR or New Regenerator	$108,000	0.32
5	7 day			
Incremental Cost-Effectiveness (8 ppmv to 2 ppmv) Including Outliers				
2	365 day	New SCR or New Regenerator	$127,000	0.25
5	7 day			

Table D-6. Incremental Cost-Effectiveness (8 ppmv to 2 ppmv) including outliers

NOx Limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Incremental Cost Effectiveness	Emission Reductions (tpd)
8 ppmv to 2 ppmv	365 day	New SCR	$127,000	0.25

Table D-7. Cost Effectiveness for FCCU after Excluding Outliers

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions (tpd)
Excluding Outliers					
FCCU	2	365 day	New SCR	$24,000	0.36
	5	7 day			

APPENDIX E GAS TURBINES

Gas Turbines

There is a total of twelve gas turbines operating at refineries in the South Coast AQMD; Gas turbines in this category range from 342 MMBtu/hr (34 MW) to 986 MMBtu/hr (83 MW). Nine of 12 gas turbines have duct burners and are in combined-cycle operation; the remaining three gas turbines have no duct burners and operate with heat recovery only. Duct burners are typically used in combined cycle and cogeneration installations to boost exhaust gas temperature upstream of the HRSG when needed. Gas turbines and duct burners emissions are controlled by post-combustion control system such as Selective Catalytic Reduction (SCR); all twelve gas turbines are equipped with SCRs. The oldest installed in in the late 1980's and newest in 2017. Out of the twelve gas turbine units, two units are entirely fired with natural gas and ten units are fired with other fuels (e.g., refinery fuel gas or refinery mixed gas). In the mixed fuel turbines, refinery gas is used as primary fuel and natural gas as secondary fuel. One refinery has the capability to fire using propane as part of the refinery gas/natural gas mix.

Process Description

Gas turbines are used in refineries to produce electricity and steam. Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40% and combined-cycle efficiencies of 60%. Aeroderivative gas turbines are adapted from aircraft engines. These turbines are lightweight and more efficient than frame turbines however the largest units are available for up to only 40-50 MW. The figure below shows a general scheme of a combined cycle gas turbine operation. Ambient air is drawn, compressed, and mixed with fuels (e.g., natural gas, refinery fuel gas, refinery mixed gas, butane) and ignited in the combustor. High temperature exhaust is produced and used to rotate one or more shafts. NOx in the exhaust flue gas is treated by catalytic reduction. Passing through the heat recovery boiler or HRGS, the thermal energy of the flue gas is recovered in the form of steam that is then used to turn an additional steam turbine.

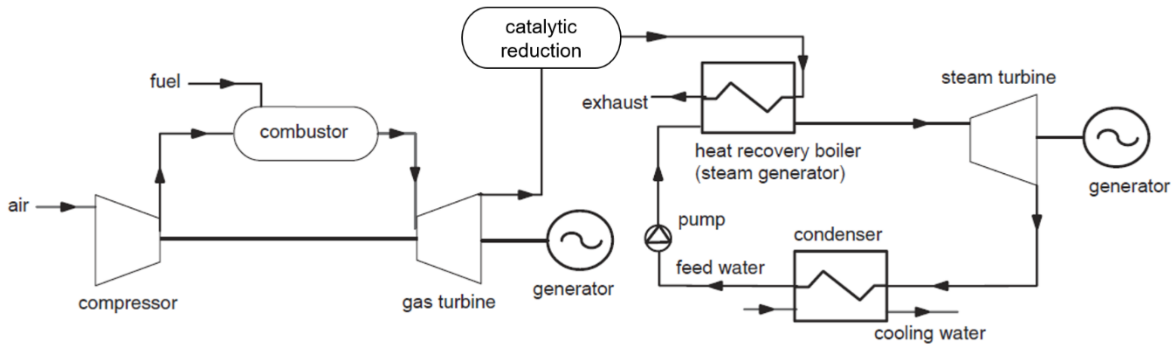


Figure E-1. Combined Cycle Gas Turbine Diagram

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Table E-1. South Coast AQMD Rules NOx Limits

Refinery Rule Limits and Assessments			
	2005 RECLAIM BARCT	**2015 RECLAIM BARCT**	**Rule 1134 (Combined Cycle)**
Refinery Gas Turbines	–	2 ppmv at 15% O_2, dry	2 ppmv at 15% O2, dry (Natural Gas)

Assessment of Emission Limits of Existing Units

The two gas turbines operating with natural gas are achieving 2 ppmv NOx limit in practice. The total NOx emissions from the other ten gas turbines (with refinery gas) located in the South Coast AQMD are 0.83 tons per day, as shown in the table below.

Table E-2. 2017 NOx Emissions for Gas Turbines

Unit	Number of Units	NOx Control	2017 NOx Emissions (tpd)	Outlet NOx at 15% O_2 (ppmv)
Gas Turbines with Natural Gas				
Gas Turbine	2	SCR	0.03	1.1 to 1.9
Gas Turbines with Refinery Gas				
Gas Turbine	10	SCR	1.38	2.8 to 6.4
Total			**1.41**	

Assessment of Other Districts NOx Rules and Limits

Table E-3. Bay Area AQMD NOx Rules and Limits for Gas Turbines

Bay Area AQMD					
Regulation 9, Rule 9 - Limits Emissions of NOx from Stationary Gas Turbines					
	Turbine Heat Input Rating (MMBTU/hr)		**Natural Gas (ppmv)**	**Refinery Fuel Gas, Waste Gas or LPG (ppmv)**	**Non-Gaseous Fuel (ppmv)**
Emission Limits, General	> 50 – 150	No retrofit	42	50	65
		Water inject/steam injection	35	50	65
		Dry Low Nox	25	50	65
	> 150 – 250		15	15	42
	> 250 – 500		9	9	25
	> 500		5	9	25
Emission Limits, Low Usage	50 – 250		42	N/A	65
	> 250		25	N/A	42

Table E-4. Texas CEQ NOx Limits for Gas Turbines

Texas Commission on Environmental Quality	
Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	
Stationary Gas Turbine Rating (MW)	**NOx Emission Limit (ppmv)**
>10	29
1 to 10	135
<1	233

Assessment of Pollution Control Technologies

Gas turbine units subject to PR 1109.1 are fired with natural gas or other fuels (e.g., refinery fuel gas). In conventional combustors, greater than 50 percent of NOx emissions are expected from refinery fuel gas. Refinery fuel gas burns at higher flame temperatures and thus, can increase NOx emissions over the NOx levels for natural gas that consists mainly of methane. Gas turbines with Dry-Low NOx (DLN) combustors can operate with stack gas NOx emission concentration as low as 9 ppmv but typically in the range of 9–25 ppmv at 15 percent O_2 without water or steam injection when operating on natural gas. DLN combustors can have approximately 10 percent greater NOx emissions when operating on refinery fuel gas.

Pre-Combustion Technologies

Dry Low-NOx or Lean Premix Emission Combustors (Natural Gas Turbines)

Prior to combustion, gaseous fuel and compressed air are pre-mixed, minimizing localized hot spots that produce elevated combustion temperatures and therefore, less NOx is formed. Atmospheric nitrogen from the combustion air is mixed with air upstream of the combustor at deliberately fuel-lean conditions. Approximately twice as much air is supplied as needed to burn the fuel. This excess air is a key to limiting NOx formation, as very lean conditions cannot produce the high temperatures that create thermal NOx. Using this technology, NOx emissions, without further controls, have been demonstrated at single digits (< 9 ppmv at 15% oxygen on a dry basis). The technology is engineered into the combustor that becomes an intrinsic part of the turbine design. Fuel staging or air staging is utilized to keep the flame within its operating boundaries. It is not available as a "retrofit" technology and must be designed for each turbine application.

Water or Steam Injection (Natural Gas Turbines)

Demineralized water is injected into the combustor through the fuel nozzles to lower flame temperature and reduce NOx emissions. Water or steam provides a heat sink that lowers flame temperature. Imprecise application leads to some hot zones, so NOx is still created. NOx levels in natural gas turbines can be lowered by 80% to 25 ppmv at 15% oxygen on a dry basis. Addition of water or steam increases mass flow through the turbine and creates a small amount of additional power. The addition of water increases carbon monoxide emissions and there is added cost to demineralize the water. Turbines using water or steam injection have increased maintenance due to erosion and wear are able to reduce NOx concentration to 5 to 7 ppmv at 3% oxygen on a dry basis. The burners are scalable for various sizes of boilers and heating units. The burners can be designed for retrofit or new installations. However, retrofits to existing gas turbines may require complex engineering and re-design.

Initial BARCT Assessment and Conditions

2015 BARCT Assessment and Norton Engineering report concluded that a 2 ppmv NOx limit is technically feasible for gas turbines in PR 1109.1 universe. Initial BARCT assessment for gas turbines subject to PR 1109.1 showed that combination of dry-low NOx (DLN) combustor and SCR can achieve 2 ppmv NOx limit with proper engineering and design. DLN combustors can achieve between 9 ppmv and 25 ppmv in gas turbines operating with natural gas and between 10 ppmv and 27.5 ppmv in gas turbines operating with refinery gas (i.e., about 10% higher NOx emissions compared with natural gas fired ones). Moreover, SCR can achieve about 95% NOx reduction in both types of gas turbines. Recent BARCT Assessments in Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) and Rule 1135 (Emissions of Oxides of Nitrogen from Electricity Generating Facilities) established 2 ppmv to be achievable for combined cycle gas turbines fired with natural gas.

The two gas turbines fired with natural gas have existing SCRs and CO catalysts with an average NOx removal efficiency of 94% by the existing SCRs. Both units currently achieving less than 2 ppmv NOx emissions. Subsequent to this analysis, staff received comments on a gas turbine with natural gas achieving a concentration level close to the proposed NOx limit and thus eligibility for a conditional limit. Staff was able to gather cost data for upgrades necessary for that unit close to the NOx limit to retrofit and meet the Table 1 NOx limit in the proposed rule. More specifically, there are four natural gas turbines at the affected facilities, of which two are achieving less than 2 ppmv NOx, including one that has a NOx permit limit of 2.5 ppmv. In order for the unit at 2.5 ppmv to meet the even lower NOx limit, the existing SCR would need to be replaced. All gas turbines operating with refinery gas have existing SCRs and CO catalysts with SCR NOx removal efficiency of 70 to 89 percent, catalysts age range between one and 12 years, and a catalyst beds range of 1 to 2. NOx removal efficiency can be improved in these units by SCR upgrade (e.g., ammonia injection grid, catalyst, additional catalyst beds) and there is a possibility of combustor upgrade between 10 to 27.5 ppmv. Stack test demonstrated that combination of DLN combustor and maximized SCR removal efficiency can technically achieve around 2 ppmv NOx. Since this initial analysis, staff received comments on the technical challenges for gas turbines fired with refinery gas to achieve 2 ppmv even with a retrofit. There are eight gas turbines at refineries that operate on refinery gas or mixed fuel achieving between 2.8 ppmv to 10 ppmv. One facility upgraded their existing SCR with the replacement with a state-of-the-art catalyst (verified by the vendor as best performing) on 2 units targeting 2 ppmv but are only achieving 3 ppmv. Refinery fuel gas has a higher heating value (HHV) and is more variable than natural gas, and HHV can result in higher NOx emissions. With the concern about technical feasibility, staff evaluated a 3 ppmv NOx limit for gas turbines fired with refinery gas since there are units operating around that level so achieved in practice.

Cost and Cost-Effectiveness Analysis

Cost-effectiveness assessment demonstrated that all existing gas turbines operating with natural gas are achieving 2 ppmv NOx limit in practice. To address the conditional limit, staff conducted a further cost-effectiveness analysis of the existing unit at 2.5 ppmv to determine if it is an outlier and whether the 2.5 ppmv would qualify as a conditional limit. As with the other conditional limit determinations, staff also had to evaluate the cost effectiveness of the remaining natural gas turbines to meet the Table 1 NOx limit. The cost for the SCR replacement was determined to be $9 million according to the U.S. EPA's SCR cost model in present worth value. As such, the cost effectiveness to reduce the NOx limit from 2.5 ppmv to 2 ppmv is $570,000 per ton of NOx reductions, and thus not cost effective, thus, qualifies as a conditional limit. For the remaining units to meet the 2 ppmv with an SCR replacement cost of $12-13 million from the U.S. EPA SCR cost model, it was concluded to be cost effective at $15,400 per ton of NOx reductions.

Staff evaluated cost-effectiveness for all gas turbines operating with refinery gas using the U.S. EPA cost model with a 20% increase for labor costs and excluded the modified cost curve best applicable to the case of heaters and boilers. Assessments established SCR upgrades as the most cost-effective option to achieve 2 ppmv NOx limit for these units. Staff also conducted cost-effectiveness analysis for these units based on associated costs with new SCR installation as a worse case cost assumption. To meet a 3 ppmv NOx concentration limit, the unit would still need control NOx efficiency 95 percent which can be done with an SCR or a dry low-NOx (DLN) combustor. Cost estimates for SCR range from $11 to $26 million and for DLN approximately $10 million. The cost effectiveness to meet the 3 ppmv from current NOx levels for refinery gas turbines was calculated to be $19,300 per ton NOx reduced but the incremental cost effectiveness to drive these units down to 2 ppmv was $74,300 per ton NOx reduced, so 2 ppmv was determined to be not cost effective.

Proposed BARCT Limits

After consulting with the South Coast AQMD-hired contractors, reviewing facility data, and considering challenges and costs for implementing the technology, South Coast AQMD staff concludes meeting a 2 ppmv NOx concentration at the stack is technically feasible and cost effective with firing natural gas and as explained above, with a conditional limit of 2.5 ppmv. For gas turbines fueled with refinery gas, the technically feasible and cost-effective limit of 3 ppmv is being proposed. Since the NOx concentrations in the flue gas into the existing SCRs are not reported in the survey, it is difficult to tell the level of NOx removal efficiency of existing SCRs. However, a typical SCR can remove up to 95 percent of NOx emissions when properly engineered and designed on the SCR performance. Existing SCRs may warrant further optimization and tuning of ammonia injection grid to improve local mixing and ammonia distribution at the SCR catalyst face. Staff recommends setting the BARCT level to 2 ppmv NOx at 15 percent O_2 for the natural gas turbines and 3 ppmv NOx at 15 percent O_2 for the other fuels (e.g., refinery fuel gas) turbines. SCR and DLN combustor NOx control technology is commercially available, technically feasible, and cost effective to achieve the proposed level.

Table E-5. Proposed BARCT Limits

	NOx limit (ppmv at 15%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions (tpd)
Gas Turbines (Natural Gas)	2	24 hours	SCR	$15,400	0.18
Gas Turbines (Other Fuels)	3	24 hours	SCR or DLN Combustor	$19,300	0.30

Staff is also proposing to include an alternative NOx limit for gas turbines operating on refinery gas during periods of natural gas curtailment, which is a shortage in the supply of pipeline natural gas, due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas. These events are infrequent but can impact local refineries. In the past year, Texas experienced a super cold winter causing pipes to freeze coupled by power outages causing a sudden demand for natural gas and thus natural gas curtailment locally. This can be problematic for refineries who supplement their refinery fuel with natural gas, and if not available, they must substitute with other fuels (e.g., propane or butane). Unfortunately, the higher heating value of the alternative fuels results in higher NOx emissions. In order to address this potential issue, staff reviewed CEMS data during this winter's natural gas curtailment and is proposing a 5 ppmv NOx limit during periods of natural gas curtailment. Since there is only one proposed NOx limit for each category of turbines, an incremental cost-effectiveness calculation could not be performed

APPENDIX F SULFUR RECOVERY UNITS/TAIL GAS INCINERATORS

Sulfur Recovery Units/Tail Gas Incinerators

There is a total of sixteen Sulfur Recovery Units/Tail Gas (SRU/TG) Incinerators operating in the South Coast AQMD, thirteen without stack heaters and three with stack heaters. The BARCT assessment was initiated and presented in Working Group Meeting #2 on June 14, 2018 and completed and presented during Working Group Meeting #10 held on February 18, 2020.

Process Description

Sulfur recovery typically refers to the conversion of hydrogen sulfide (H_2S) to elemental sulfur. H_2S is a byproduct of refining and processing high-sulfur crudes slates. Amine treating units are used to recover H_2S from various sour gas streams at the refineries. The acid gases from the amine units are sent to sulfur plant for conversion to elemental sulfur. The most common conversion method used in the South Coast Air District is Claus process which typically recovers 95 to 97 percent of the hydrogen sulfide in the feed stream. The SRU (Claus unit) consists of a reactor and series of converters and condensers. Approximately 95% of sulfur from the gaseous streams is recovered after passing through the SRU. The tail gas is then sent to an amine absorption unit, or diethanol amine (DEA), SCOT, Wellman-Lord, and FLEXSORB to absorb and recover the remaining sulfur. Approximately 99% or the remaining sulfur is absorbed and recovered after the amine units. An SRU/TG incinerator is typically located downstream of a Claus where any residual H_2S in the tail gas is oxidized to SO_2 before being emitted into the atmosphere. The refinery SRU/TG Incinerator are classified as major sources of NOx and SOx. The downstream SRU/TG Incinerators runs at high excess O_2 and low combustion temperatures, so thermal NOx formation is minimal – NOx emissions from the SRU incinerators are the result of NOx concentration in the inlet gas stream.

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Since the interception of the RECLAIM in 1993 until 2010, the South Coast AQMD did not set any BARCT standards for the SRU/TG. However, as part of the BARCT assessment, regulatory requirements for SRU/TG in the South Coast AQMD is shown in the table below. The 2015 RECLAIM BARCT NOx limit was determined 2 ppmv corrected to 3 percent oxygen.

Table F-1. South Coast AQMD Rules NOx Limits

Refinery NOx Limits and Assessments	
2015 RECLAIM BARCT	
Sulfur Recovery Units/Tail Gas Incinerator	2 ppmv NOx at 3% O_2, dry

Assessment of Emission Limits of Existing Units

As shown in the table below, the total NOx emissions from the SRU/TG Incinerators located in the South Coast AQMD are 0.43 tons per day. Currently no units have been retrofitted with post-combustion control and their annual average outlet NOx concentrations ranging from as low as 4 to 98 parts per million by volume, dry (ppmv), depending on the type of fuel fired and operating conditions. Three SRU/TG Incinerators have permit limits and are operating below their permit limits based on the annual average as reported in the survey.

Table F-2. NOx Emissions for SRU/TG Incinerators

Units	Number of Units	Size (MMBtu/hr)	2017 NOx Emissions (tpd)	NOx in Flue Gas @ 3% O_2 (ppmv)
SRU/TG Incinerator	19	10 to 100	0.43	4 to 98

Assessment of Other Districts NOx Rules and Limits

Table F-3. Other District NOx Limits

Texas Commission on Environmental Quality (TCEQ)	
Title 30, Part 1 Chapter 117, Subchapter B, Division 3, RULE §117.310	
Incinerators	NOx Emission Limit (ppmv*)
Incinerators (excluding vapor streams resulting from vessel cleaning routed to an incinerator, provided that fuel usage is quantified using good engineering practices)	27 ppmv (@3%, O_2, dry)
	80% reduction from the daily NOx emissions

Assessment of Pollution Control Technologies

Commercially available NOx control technologies for this category are LNB/ULNB, SCR, and LoTOx™. SCR is a post-combustion control technology that requires an optimal temperature window to achieve maximum reductions, thus a waste heat boiler may be necessary to reduce flue gas temperatures to SCR operating temperatures. This can add cost and additional space requirements. SCR can be designed to reduce 95% NOx emissions. One potential drawback of SCR for this application is the high SO_3 content in the flue gas which can lead to ammonium bisulfate fouling, making SCR impractical for this category. However, LoTOx™ operates at lower temperatures and is used in conjunction with a WGS to reduce NOx, and SOx. LoTOx™ with wet gas scrubber technology is a good candidate provided that space is available for equipment. The LoTOx™ system requires an ozone generation system on site and waste effluent treatment for the wastewater generated from the LoTOx™ process. Depending on the location of the facility, building a waste effluent treatment system may also not make the technology practical. Staff has not identified any location where post-combustion is used for controlling NOx. The most practical option for the category is custom designed LNB/ULNB upgrades which can be designed to reduce up to 80 percent NOx emissions (<30 ppmv) similar to the sulfuric acid plant furnaces. Several burner manufacturers have dedicated business divisions that specialize in this particular application.

Initial BARCT Assessment and Considerations

Based on the current flue gas NOx emissions of 58 to 100 ppmv in the flue gas and the fact that most post-combustion control can achieve greater than 95% NOx reductions, staff determined a NOx limit of 2 to 30 ppmv is technically feasible. These limits were used to assess the cost effectiveness.

Costs and Cost-Effectiveness Analysis

SCR Costs

Staff received one cost estimate from a facility for a SCR retrofit at a cost of approximately $60 MM for two units with common SCR. Cost estimate for the remaining units were determined as follows:

- SCR cost ~$45 per standard cubic feet of stack flow rate which was received from a SCR vendor
- Waste heat boiler at ~ $100,000 which is needed to cool the gas to SCR operating temperature
- Installation costs estimated at approximately 4.5 times capital cost (based on 2015 BARCT Norton Engineering recommendation)
- Operating and maintenance estimated to be approximately $150,000/year

Eight units exceed the 95% reduction to achieve 2 ppmv and would need to replace the burners, so staff included the cost of burners to achieve 2 ppmv – the burner cost curve was used to estimate cost. There were no units that needed burner upgrade to get to 5 ppmv. Despite being technically feasible to retrofit to 2 or 5 ppmv with SCR, it was not cost effective which is shown in the table below.

Table F-4. SCR Cost-Effectiveness

Cost-Effectiveness at 2 and 5 ppmv	
2 ppmv (SCR and ULNB)	5ppmv (SCR)
$107,000	$125,000

LoTOx™ Costs

Staff relied on 2015 BARCT assessment to estimate costs for LoTOx™ control technology with three data points and scaled costs up using 4% interest rate and created cost curve for total install and O&M costs. Eight units exceed 95% reduction to achieve 2 ppmv and would replace burners. Burner cost curve used to estimate cost. No unit needs to replace burners to achieve 5 ppmv. Similar to SCR, although it was technically feasible to retrofit to 2 or 5 ppmv with LoTOx™ technology, it was not cost effective as shown in the table below.

Table F-5. LoTOx™ Cost-Effectiveness

Cost-Effectiveness at 2 and 5 ppmv	
2 ppmv (LoTOx™ and ULNB)	**5ppmv (LoTOx™)**
$71,000	$65,000

ULNB Costs

Staff received additional cost in the from facilities which were used to revise the burner cost curve. The burner cost curve was used to estimate burner costs and the average cost was about $3.1 MM. However, the operating and maintenance costs was estimated to be about $2,000 per year. Nine units currently operating above 30 ppmv and need to retrofit. The ULNB technology is feasible, but it is also cost effective to retrofit SRU/TG Incinerator to 30 ppmv using ULNB technology as it is shown in the table below.

Table F-6. ULNB Cost-Effectiveness

Cost-Effectiveness at 30 ppmv
ULNB
$39,000

Proposed BARCT Limits

After consulting with the NOx control technology manufacturers, reviewing facility data, and the 2015 BARCT assessment, staff recommends setting a new BARCT level of 30 ppmv NOx for SRU/TG Incinerators based on burner technology which is technically feasible and cost effective. Nine units out of sixteen need to retrofit based on the new BARCT limit. Achieving 2 or 5 ppmv with SCR and LoTOx™ technologies were technically feasible but not cost-effective. The BARCT assessment for the 2015 RECLAIM shave concluded a 2 ppmv NOx limit was technically feasible and cost-effective. The NOx shave was to reduce emissions from RECLAIM facilities and staff only evaluated the higher emitting SRU/TG Incinerators. PR 1109.1 is a command-and-control rule, so staff had to evaluate each unit in the class and category. When all the units were assessed, neither 2 ppmv nor 5 ppmv was cost-effective. An incremental cost-effectiveness was not conducted because no other control technology was identified as cost-effective.

Table F-7. Proposed BARCT Limits

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions tpd
Sulfur Recovery Units/Tail Gas Incinerators	30	24 hours	LNB	$39,000	0.1

APPENDIX G FLARES AND VAPOR INCINERATORS

Flares and Vapor Incinerators

There is a total of fourteen units in the category, includes one flare and thirteen afterburners, vapor incinerators, and thermal oxidizers. The following BARCT assessment was initiated and presented in Working Group Meeting #3 on August 1, 2018 and completed and presented during Working Group Meeting #12 held on July 17, 2020. The following is the summary of the BARCT assessment.

Process Description

Flare

A flare is a control device that is utilized to control a VOC stream by piping it to a burner that combusts the VOC containing gases. Early flares were designed as elevated, candlestick-type flares that have an open flame with a specially designed burner tip, and auxiliary fuel to achieve nearly 98 percent VOC destruction. Complete combustion results in the conversion of all the VOCs to carbon dioxide and water but also results in emission of NOx, SOx, and CO. Open flares have a high rated capacity and long service life. They are low-cost, simple to use, and reliable but they are also noisy, emit smoke, heat radiation, and light. Open flares cannot be source tested due to the open flame and absence of a stack.

The new generation of ultra-low NOx flare utilizes a pre-mixed gas stream with air-assist combustion and is designed with an ULNB to decrease NOx and VOC emissions. These ultra-low NOx flares can achieve NOx emissions of less than 0.025 pounds per MMBtu. The technology has been available for almost a decade. There are two major manufactures of these ultra-low NOx flares. John Zink Hamworthy Combustion (John Zink) produces Zink Ultra Low Emissions (ZULE®) flare, which electronically control air-to-fuel ratio within the enclosed flare to provide more efficient destruction and less NOx emissions without an increase of CO emissions. The other ultra-low NOx flare is the Certified Ultra-Low Emissions Burner (CEB®) produced by the Aereon Corporation. It incorporates the premixing of gases and patented wire mesh burner technology that allows for more surface area, resulting in more efficient combustion and retention of heat, with a decrease of NOx emissions. Due to the added complexity in the design of the ultra-low NOx flares, some stakeholders have experienced reliability issues. This is especially true of the early generation flares installed that do not combust a constant gas flow. More recently, Perennial Energy has introduced an ultra-low NOx flare which guarantees 0.025 pounds of NOx per MMBtu and 0.06 pounds of CO per MMBtu. These flares have a smaller footprint and 100 percent stainless steel burners, and they use technology that involves automatic air fuel ratio controls with proprietary burner technology.

The flares subject to PR 1109.1 are not the same type as the refinery flares subject to Rule 1118. Rule 1118 flares are tall stacks equipped with a burner, used to destroy any excess gases produced by refineries, sulfur recovery plants, and hydrogen production plants. Flare systems are in operation all the time. Most of the time these systems are in standby mode, ready to combust gases as soon as they enter the flare. Flaring occurs to ensure safety during scheduled maintenance, the startup/shutdown of a process unit, or other activities where a refinery or related source can reasonably anticipate the need to dispose excess gases that cannot be safely recycled into the facility. Flaring also occurs to ensure safety during emergencies caused by equipment breakdown, power outage, or other upset beyond a refinery's control. The flares safely burn excess gases that could otherwise pose potential risks to workers, the community, or the environment. The following figure illustrate the applicability of each rule.

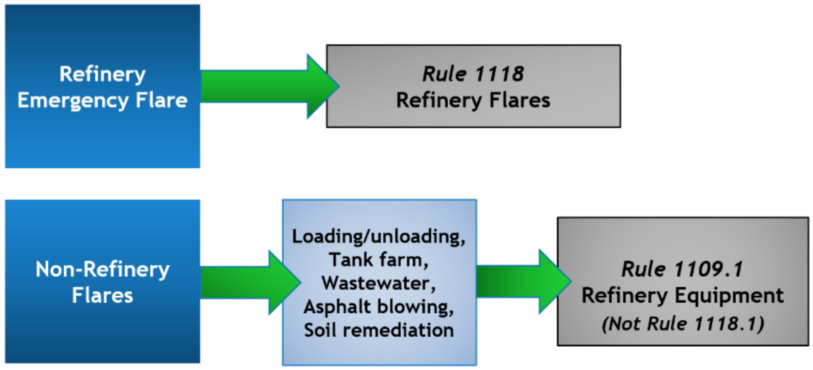


Figure G-1. South Coast AQMD Flare Regulations

Vapor Incinerator

Vapor Incinerators are one of the most proven methods to control VOCs emissions released form industrial sources by means of thermal destruction. The term "incineration" refers to an ultimate disposal method which is a thermal treatment of waste materials (solid, liquid, or gas) through a combustion process in the presence of oxygen. The combustion process increases the temperature of the material to higher than its auto-ignition point and maintains the high temperature for enough time to complete the combustion to carbon dioxide and water. Time, temperature, turbulence, and available oxygen are the basic design parameters for incinerators since they affect the efficiency of the combustion process. The terms "incinerator" and "oxidizer" are used interchangeably for thermal treatment of gaseous waste streams of VOCs and/or hazardous air pollutants (HAP).

There are two broad classes of oxidizers: thermal systems and catalytic systems. Thermal systems may include direct flame incinerators with no energy recovery, flame incinerators with a recuperative heat exchanger (Recuperative Thermal Oxidizers), or regenerative systems that operate in a cyclic mode to achieve high energy recovery (Regenerative Thermal Oxidizers). Catalytic systems are fixed-bed or fluid-bed systems which can provide energy recovery.

Thermal Oxidizers

The main part of the thermal oxidizer is a nozzle-stabilized flame which heats the waste gas as it passes through to its ignition temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, and therefore, any waste stream material mixture will burn. The mixture continues to react as it flows through the combustion chamber. The nozzle-stabilized flame is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. The reactor temperature is defined based on the required level of VOC control of the waste gas to be achieved and the residence time of the stream in the thermal combustion chamber dictates the reactor temperature.

Carbon dioxide and water are the most abundant elements in the exhaust gases from thermal oxidizers, however, the incineration of nitrogen-bound wastes at high temperatures in a thermal oxidizer generates high levels of nitrogen oxide emissions. Moreover, often auxiliary fuel (e.g., natural gas) must be added to the waste gas stream to help with raising its temperature to the desired levels if the combustion of VOCs in the stream is not enough to provide the temperature. Process adjustments such as using low-NOx burners or controls using reducing agents such as ammonia and urea-based scrubbers are effective to reduce the formation of nitrogen oxide in thermal oxidizers. The incoming waste stream and/or auxiliary air can be preheated in a recuperative heat exchanger using the effluent stream containing the products of combustion which could decrease auxiliary fuel requirements and improve energy efficiency.

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Table G-1. South Coast AQMD Rule NOx Limits

NOx Limits and Assessments	
South Coast AQMD Rule 1147	
Incinerator, Afterburner, Remediation Unit, and Thermal Oxidizer	60 ppmv or 0.073 lb/MMBTU
South Coast AQMD Rule 1118.1	
Non-Refinery Flares	Replacement with 20 ppmv flare (0.025 lb/MMBtu) if throughput capacity > 5%

Assessment of Emission Limits of Existing Units

As shown in the table below, the total NOx emissions from the flare and vapor incinerators located in the South Coast AQMD are 0.05 tons per day. Currently no units have been retrofitted with post-combustion control and their annual average outlet NOx concentrations ranging from 9 ppmv to 134 ppmv corrected to 3 percent oxygen, depending on the type of fuel fired and operating conditions. Five vapor incinerators have permit limits and are operating below the permit limits.

Table G-2. NOx Emissions for Flares and Vapor Incinerators

Units	Number of Units	Size (MMBtu/hr)	2017 NOx Emissions (tpd)	NOx in Flue Gas @ 3% O_2 (ppmv)
Vapor Incinerator	13	1.2 to 60	0.05	9 to 134
Flare	1	1.09	0.0005	

Assessment of Other Districts NOx Rules and Limits

Table G-3. Other District NOx Limits

San Joaquin Valley Air Pollution Control District	
Rule 4311 – FLARES	
Type of Flare and Heat Release Rate in MMBtu/hr	**NOx Emission Limit (lb/MMBtu)**
Enclosed Flare	
Without Steam-assist	
< 10	0.0952
10 – 100	0.1330
> 100	0.5240
With Steam-assist	
All Sizes	0.068
Other Types of Flares	
Flares at Oil and Gas Operations or Chemical Operations	0.018
Flares at Landfill Operations	0.025
Flares at Digester Operations (Located at a Major Source)	0.025
Flares at Digester Operations (Not located at a Major Source)	0.060

Assessment of Pollution Control Technologies

As the units in this category are very small (1-30 MMBtu/hr) installing a SCR control technology will not be cost effective. The best NOx control option is the burner control. Staff evaluated similar sized units from the Rule 1147 universe to assess technical feasibility of 20 ppmv. Vapor incinerators at refineries operate similarly to units at other facilities that are primarily used for VOC control although the constituents being burned could be different. Available source test results demonstrated LNB for vapor incinerators could achieve 20 ppmv.

There is only one open flare in the PR1109.1 universe. Open flares cannot be retrofitted with LNB. PR 1109.1 will include a low emission exemption for flares of less than or equal to 550 pounds of NOx per year. In addition, when the burners are being replaced, the cleanest technology will be required.

Initial BARCT Assessment and Considerations

Based on the current NOx emissions in the flue gas from thermal oxidizers and flare, and the small emissions and small units in this category, staff initially determined that 20 ppmv NOx limit for thermal oxidizers with burner replacement and flares with flare replacement is technically feasible and the limit should be determined based on the cost effectiveness analysis. There is a total of 15 units in this category, and they are primarily used for air pollution control to destruct volatile organic compounds and other waste gas streams. The units are relatively small with most units <10 MMBtu/hr and emissions tend to be low at 0.078 tons per day NOx for all units. Several stakeholders expressed concerns about the technical feasibility of achieving 20 ppmv including the concern that the waste stream and units fired on process gas could contribute to the NOx emissions and that some advanced retrofit burner technology options may require redesign/re-engineering of the entire system because unit replacement may be required to achieve 20 ppmv. Staff reached out to several burner manufacturers to reassess the technical feasibility of the 20 ppmv NOx limit. These technology vendors indicated they would guarantee 30 ppmv NOx for burner replacements although some units could be tuned to achieve <20 ppmv but it is dependent on the unit, application, and fuel, so not all units will be able to achieve 20 ppmv. Due to the concern with technical feasibility of 20 ppmv for this category, staff reassessed the cost effectiveness to achieve 30 ppmv NOx from burner upgrades.

Similar to other equipment projects, stakeholders provided revised cost data that included some costs higher than originally analyzed and could be identified as outliers. Overall, cost-effectiveness of vapor incinerators is below the established $50k threshold but several units have very high cost-effectiveness including four units with cost-effectiveness of ~$100,000 - $500,000 per ton NOx reduced. These units are currently preforming between 38 – 40 ppmv and the high cost-effectiveness is likely due to higher costs but low emission reductions. As such, the total potential emission reduction for those units is 0.0025 tons per day. Thus, staff is proposing a conditional limit of 40 ppmv.

Costs and Cost-Effectiveness Analysis

Vapor Incinerators

Staff received some revised costs from equipment in this category and for those units without cost provided, staff relied on a cost curve for burner replacement developed for Proposed Amended Rule 1147 – Miscellaneous NOx Sources and increased the estimated cost by 20% to account for Senate Bill 54. The burner replacement costs ranged from $300,000 to $7.2 million and it was determined to be cost effective at $35,000 per ton of NOx emissions reduced for burner replacement in order to meet the 30 ppmv NOx limit. Potential emission reduction is 0.048 tons per day NOx. For the conditional limit of 40 ppmv, those units are already meeting the proposed limit so no additional cost would be imposed, thus zero dollars per ton cost effectiveness. An incremental cost-effectiveness was not conducted because no other control technology was identified.

Flares

Staff relied on costs developed for the oil and gas industry for Rule 1118.1 – Emission Reductions for Non-Refinery Flares and increased the estimated cost by 20% to account for Senate Bill 54. New Low-NOx flares costs about $625,000 and annual Operation and Maintenance costs assumed to be $36,000. As shown in table below, it is not cost effective to achieve 20 ppmv with flare replacement until the unit is being replaced or exceeds the exemption limit at which time the new unit would be expected to meet 20 ppmv using the cleanest burner technology. An incremental cost-effectiveness was not conducted for units without existing controls because no other control technology was identified.

Table G-4. Cost-Effectiveness

Cost Effectiveness to 20 ppmv	
Vapor Incinerators	$35,000
Flares	~$500,000

Proposed BARCT Limits

After consulting with the NOx control technology manufacturers, reviewing facility data, and performing BARCT assessment, staff recommends setting a new NOx limit of 30 ppmv NOx for vapor incinerators with burner replacement using LNB technology with low-emitting exemption of 100 pounds NOx/year. Staff also recommends low use exemption of 550 lbs per year.

Table G-5. Proposed BARCT Limits

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)
Vapor Incinerators	30	3 hours	LNB	$35,000
Flares	20	3 hours	Low-NOx Flare	N/A[1]

(1) Existing flare will fall under low-use exemption, replacement will be required if usage exceeds the 20-hour exemption.

APPENDIX H FACILITY EMISSIONS BY UNIT

Table H-1. Chevron Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

CHEVRON									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D641	Heater	365	68.3	24.0	5.0	14.2	N/A	N/A	Not Eligible, Red > 20 TPY
D643	Heater	220	26.2	20.3	5.0	6.5	22.0	28.4	Table D-1 Eligible
D451	Heater	102	37.0	69.8	5.0	2.6	N/A	N/A	Not Eligible, Red > 10 TPY
D3053	Gas Turbine	506	49.0	6.4	2.0	15.3	2.5	19.1	Possibly Eligible
D203	FCCU	-	49.7	6.0	2.0	16.6	8.0	66.2	Eligible
D3973	FCC SU Heater	165	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D2198	Gas Turbine	560	41.5	8.3	2.0	10.0	2.5	12.5	Possibly Eligible
D20	Heater	217	27.9	31.3	5.0	4.5	N/A	N/A	Not Eligible, Red > 20 TPY
D625	Heater	63	24.9	58.6	5.0	2.1	N/A	N/A	Not Eligible, Red > 10 TPY
D617	Heater	57	23.8	105.0	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D623	Heater	63	23.8	53.8	5.0	2.2	N/A	N/A	Not Eligible, Red > 10 TPY
D2207	Gas Turbine	560	40.2	4.4	2.0	18.3	2.5	22.9	Possibly Eligible
D502	Heater	70	21.5	85.0	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY
D619	Heater	57	19.2	74.3	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY
D504	Heater	77	18.1	83.9	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D618	Heater	57	17.5	82.8	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D620	Heater	57	17.1	74.3	5.0	1.2	N/A	N/A	Not Eligible, Red > 10 TPY

CHEVRON									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D2216	Boiler	342	15.5	47.4	5.0	1.6	7.5	2.5	Possibly Eligible
D82	Heater	315	6.3	7.9	5.0	4.0	22.0	17.6	Table D-1 Eligible
D83	Heater	315	6.9	7.9	5.0	4.4	22.0	19.3	Table D-1 Eligible
D84	Heater	219	5.4	7.9	5.0	3.4	22.0	15.1	Table D-1 Eligible
D159	Heater	176	14.9	10.4	5.0	7.1	N/A	N/A	Not Eligible, Red > 20 TPY
D160	Heater	176	16.5	10.4	5.0	8.0	N/A	N/A	Not Eligible, Red > 20 TPY
D161	Heater	176	17.1	10.4	5.0	8.2	N/A	N/A	Not Eligible, Red > 20 TPY
D955	SRU/TGI	58	22.4	58.3	30.0	11.5	N/A	N/A	No Table 2 Limit
D927	SRU/TGI	30	15.7	53.0	30.0	8.9	N/A	N/A	No Table 2 Limit
D466	Heater	33	3.4	7.8	9.0	3.9	N/A	N/A	No Table 2 Limit
D467	Heater	33	3.6	7.8	9.0	4.2	N/A	N/A	No Table 2 Limit
D911	SRU/TGI	30	15.4	43.4	30.0	10.7	N/A	N/A	No Table 2 Limit
D390	Heater	31	6.0	28.3	9.0	1.9	N/A	N/A	No Table 2 Limit
D453	Heater	44	3.5	21.3	5.0	0.8	18.0	3.0	Possibly Eligible
C3493	Vapor Incinerator	3	3.7	45.1	30.0	2.5	40.0	3.3	Possibly Eligible
D1910	Heater	37	3.8	38.0	9.0	0.9	N/A	N/A	No Table 2 Limit
D398	Heater	19	3.7	38.0	9.0	0.9	N/A	N/A	No Table 2 Limit
C2158	Vapor Incinerator	3	3.1	86.3	30.0	1.1	40.0	1.4	Possibly Eligible
D428	Heater	36	4.4	41.7	9.0	0.9	N/A	N/A	No Table 2 Limit
D364	Heater	26	2.0	18.1	9.0	1.0	N/A	N/A	No Table 2 Limit
C3148	Vapor Incinerator	1	0.018	80.1	30	N/A	N/A	N/A	Exempt (o)(9)
C3805	Vapor Incinerator	2	0	-	30	N/A	N/A	N/A	Exempt (o)(9)
C3806	Vapor Incinerator	2	0.032	28.3	30.0	N/A	N/A	N/A	Exempt (o)(9)
D3778	Heater	78	0.6	1.3	5.0	2.5	N/A	N/A	Not Eligible, Meets Table 1 Limit

CHEVRON									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D3695	Heater	83	0.8	1.9	5.0	2.1	N/A	N/A	Not Eligible, Meets Table 1 Limit
D473	Heater	88	0.4	1.7	5.0	1.3	N/A	N/A	Not Eligible, Meets Table 1 Limit
D472	Heater	123	0.7	1.7	5.0	2.0	N/A	N/A	Not Eligible, Meets Table 1 Limit
D471	Heater	177	0.8	1.7	5.0	2.3	N/A	N/A	Not Eligible, Meets Table 1 Limit
D3031	Heater	199	1.0	1.7	5.0	3.1	N/A	N/A	Not Eligible, Meets Table 1 Limit
D3530	SMR Heater	653	9.1	1.5	5.0	30.5	N/A	N/A	Not Eligible, Meets Table 1 Limit
D4354	Gas Turbine	509	9.1	1.1	2.0	16.6	N/A	N/A	Not Eligible, Meets Table 1 Limit
C4344	SRU/TGI	50	2.9	4.2	30.0	20.6	N/A	N/A	Not Eligible, Meets Table 1 Limit

Table H-2. Phillips 66 Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

PHILLIPS 66										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D688	Wilm	Boiler	250	56	79	5.0	4	N/A	N/A	Not Eligible, Red > 20 TPY
D154	Wilm	Heater	110	16	64	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY
D155	Wilm	Heater	100	14.5	64	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D156	Wilm	Heater	70	10	64	5.0	0.8	N/A	N/A	Not Eligible, Red > 10 TPY
D157	Wilm	Heater	42	6	64	5.0	0.5	N/A	N/A	Not Eligible, Red > 10 TPY
D158	Wilm	Heater	24	3.5	64	5.0	0.3	N/A	N/A	Not Eligible, Red > 10 TPY
D1	Wilm	FCCU	-	57	14	2.0	8	N/A	N/A	Not Eligible
D44	Wilm	FCC SU Heater	87	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D687	Wilm	Boiler	179	41	61	5.0	3	N/A	N/A	Not Eligible, Red > 20 TPY
D135	Wilm	Heater	116	13.6	38	5.0	1.8	N/A	N/A	Not Eligible, Red > 20 TPY
D136	Wilm	Heater	68	8.2	38	5.0	1.1	N/A	N/A	Not Eligible, Red > 20 TPY
D137	Wilm	Heater	71	8.6	38	5.0	1.1	N/A	N/A	Not Eligible, Red > 20 TPY
D138	Wilm	Heater	56	6.6	38	5.0	0.9	N/A	N/A	Not Eligible, Red > 20 TPY
D139	Wilm	Heater	19	2	38	5.0	0.3	N/A	N/A	Not Eligible, Red > 20 TPY
D684	Wilm	Boiler	304	29	101	5.0	1	N/A	N/A	Not Eligible, Red > 20 TPY

PHILLIPS 66										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D828	Wilm	Gas Turbine	646	46	4.5	3.0	30.5	N/A	N/A	No Table 2 Limit
D264	Wilm	Heater	135	25	56	5.0	2	N/A	N/A	Not Eligible, Red > 20 TPY
D194	Wilm	Heater	60	20	82	5.0	1	N/A	N/A	Not Eligible, Red > 10 TPY
D146	Wilm	Heater	76	11	30	5.0	2	18.0	6	Possibly Eligible
D686	Wilm	Boiler	304	9	10	5.0	5	7.5	7	Possibly Eligible
D220	Wilm	SMR Heater	350	9	8	5.0	6	7.5	8	Possibly Eligible
D333	Wilm	Sulfuric Acid Furnace	74	9	14	30.0	19	N/A	N/A	Not Eligible, Meets Table 1 Limit
D332	Wilm	Sulfuric Acid SU Heater	15	0	190	9	N/A	N/A	N/A	Exempt per (o)(6)
D262	Wilm	Heater	37	5	37	9.0	1	N/A	N/A	No Table 2 Limit
D148	Wilm	Heater	27	4.3	37	9.0	1	N/A	N/A	No Table 2 Limit
D259	Wilm	Heater	39	4.4	37	9.0	1.1	N/A	N/A	No Table 2 Limit
D152	Wilm	Heater	30	4	37	9.0	1	N/A	N/A	No Table 2 Limit
D150	Wilm	Heater	38	3.6	37	9.0	0.9	N/A	N/A	No Table 2 Limit
D133	Wilm	Heater	35	3.2	37	9.0	0.8	N/A	N/A	No Table 2 Limit
D161	Wilm	Heater	31	3.5	37	9.0	0.8	N/A	N/A	No Table 2 Limit
D39	Wilm	Heater	29	2.5	37	9.0	0.6	N/A	N/A	No Table 2 Limit
D329	Wilm	Heater	29	2.5	37	9.0	0.6	N/A	N/A	No Table 2 Limit
D142	Wilm	Heater	17	2.2	37	9.0	0.5	N/A	N/A	No Table 2 Limit
D129	Wilm	Heater	27	1.8	37	9.0	0.4	N/A	N/A	No Table 2 Limit
D163	Wilm	Heater	14	1.4	37	9.0	0.3	N/A	N/A	No Table 2 Limit
D260	Wilm	Heater	17	1.4	37	9.0	0.3	N/A	N/A	No Table 2 Limit
D40	Wilm	Heater	10	1	37	9.0	0	N/A	N/A	No Table 2 Limit
D1720	Wilm	Heater	41	0	3	5.0	1	N/A	N/A	Not Eligible, Meets Table 1 Limit

PHILLIPS 66										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D1349	Wilm	SMR Heater	460	9	4	5.0	11	N/A	N/A	Not Eligible, Meets Table 1 Limit
C436	Wilm	SRU/TGI	20	2	19	30.0	4	N/A	N/A	No Table 2 Limit
C456	Wilm	SRU/TGI	20	3	15	30.0	6	N/A	N/A	No Table 2 Limit
D430	Carson	Boiler	352	96	77	5.0	6	N/A	N/A	Not Eligible, Red > 20 TPY
D210	Carson	SMR Heater	340	90.4	64	5.0	7.1	N/A	N/A	Not Eligible
D59	Carson	Heater	350	73	40	5.0	9	N/A	N/A	Not Eligible, Red > 20 TPY
D174	Carson	Heater	70	18.5	75	5.0	1.2	18.0	0.4	Possibly Eligible
D105	Carson	Heater	175	21	30	5.0	3	22.0	15	Possibly Eligible
D104	Carson	Heater	175	19	30	5.0	3	22.0	14	Possibly Eligible
D79	Carson	Heater	154	18	25	5.0	4	22.0	16	Possibly Eligible
D78	Carson	Heater	154	17	23	5.0	4	22.0	17	Possibly Eligible
D429	Carson	Boiler	352	14	10	5.0	7	7.5	10	Possibly Eligible
D713	Carson	Heater	22	1.6	30	9.0	0.5	N/A	N/A	No Table 2 Limit
C292	Carson	SRU/TGI	15	1	11	30.0	3	N/A	N/A	Not Eligible, Meets Table 1 Limit
C294	Carson	SRU/TGI	28	17	26	30.0	19	N/A	N/A	Not Eligible, Meets Table 1 Limit

Table H-3. Marathon Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D27	Carson	Heater	550	56.5	21	5	13.3	22	58.6	Not Eligible, Red > 20 TPY
D20	Carson	Coke Calciner	120	260.9	65	5	20.1	N/A	N/A	No Table 2 Limit
D570	Carson	SMR Heater	650	48.9	11	5	22.9	7.5	34.3	Table D-2 Eligibility
D629	Carson	Heater	173	27.5	32	5	4.3	22	19.1	Not Eligible, Red > 20 TPY
D535	Carson	Heater	310	27.9	23	5	6	22	26.2	Not Eligible, Red > 20 TPY
D532	Carson	Heater	255	20.8	16	5	6.3	22	27.7	Table D-1 and D-2 Eligible
D31	Carson	Heater	130	18.3	30	5	3	22	13.3	Not Eligible >25 ppmv
D151	Carson	Heater	130	18.1	36	5	2.5	22	11.2	Not Eligible >25 ppmv
D155	Carson	Heater	130	17.5	34	5	2.6	22	11.3	Not Eligible >25 ppmv
D423	Carson	Heater	80	16.5	73	5	1.1	18	4.1	Not Eligible, Red > 10 TPY
D153	Carson	Heater	130	16.9	33	5	2.6	22	11.3	Not Eligible >25 ppmv
D67	Carson	Heater	120	15.4	31	5	2.5	22	11.1	Not Eligible >25 ppmv
D29	Carson	Heater	150	14.8	28	5	2.6	22	11.6	Not Eligible >25 ppmv
D33	Carson	Heater	100	11.4	24	5	2.4	18	8.7	Table D-2 Eligibility
D539	Carson	Heater	52	5.4	23	5	1.2	18	4.2	Table D-2 Eligibility
D421	Carson	Heater	82	4.6	18	5	1.3	18	4.8	Table D-1 and D-2 Eligible
D625	Carson	Heater	39	5.4	23	9	N/A	N/A	N/A	N/A
C54	Carson	SRU/TGI	52	5.9	68	30	2.6	N/A	N/A	No Table 2 Limit

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D250	Carson	Heater	89	3	22	5	0.7	18	2.5	Table D-2 Eligible
C910	Carson	SRU/TGI	45	25.1	34	30	22.4	N/A	N/A	No Table 2 Limit
C2413	Carson	SRU/TGI	40	14.1	19	30	22.5	N/A	N/A	No Table 2 Limit
D538	Carson	Heater	39	4.2	20	9	N/A	N/A	N/A	N/A
D416	Carson	Heater	24	3.4	28	9	N/A	N/A	N/A	N/A
D626	Carson	Heater	39	3.3	28	9	N/A	N/A	N/A	N/A
D628	Carson	Heater	39	3.4	23	9	N/A	N/A	N/A	N/A
D63	Carson	Heater	360	5.3	5.1	5	5.2	22	23	Table D-1 and D-2 Eligible
D541	Carson	Heater	39	4.3	16	9	N/A	N/A	N/A	N/A
D1465	Carson	SMR Heater	427	11	5.1	5	10.8	7.5	16.1	Table D-1 and D-2 Eligible
D627	Carson	Heater	39	3.7	17	9	N/A	N/A	N/A	N/A
C56	Carson	SRU/TGI	45	2.4	98	30	0.7	N/A	N/A	No Table 2 Limit
D419	Carson	Heater	52	1.9	15	5	0.6	18	2.3	Table D-1 and D-2 Eligible
D425	Carson	Heater	22	2.4	28	9	N/A	N/A	N/A	N/A
D1433	Carson	Heater	13	1.4	31	9	N/A	N/A	N/A	N/A
D418	Carson	Heater	11	1.3	34	9	N/A	N/A	N/A	N/A
D417	Carson	Heater	10	1.3	17	9	N/A	N/A	N/A	N/A
D1233	Carson	Gas Turbine	1,326	54.8	3	3	54.8	N/A	N/A	No Table 2 Limit
D1239	Carson	Gas Turbine	1,326	53.4	2.7	3	59.3	N/A	N/A	No Table 2 Limit
D1226	Carson	Gas Turbine	1,326	49.7	2.6	3	57.3	N/A	N/A	No Table 2 Limit
D1236	Carson	Gas Turbine	1,326	55.9	2.7	3	62.1	N/A	N/A	No Table 2 Limit
D164	Carson	FCCU	-	7.3	1	2	12.2	8	48.7	Not Eligible, Meets Table 1 Limit
D2837	Carson	FCC SU Heater	165	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
C2979	Carson	Vapor Incinerator	4	2.6	35	30	2	40	2.6	Table D-1 and D-2 Eligible

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D724/ D725	Wilm	Boiler	368	132.9	114	5	5.8	7.5	8.8	Not Eligible, Red > 20 TPY
D722/ D723	Wilm	Boiler	368	108.8	83	5	6.5	7.5	9.8	Not Eligible, Red > 20 TPY
D76/ D77	SRP	Boiler	225	34.7	48	5	3.6	7.5	5.5	Not Eligible, Red > 20 TPY
D812	Wilm	Gas Turbine	392	65.4	8	3	25.2	N/A	N/A	No Table 2 Limit
D810	Wilm	Gas Turbine	392	59.6	10	3	18.1	N/A	N/A	No Table 2 Limit
D32	Wilm	Heater	218	43.1	59	5	3.7	22	16.2	Not Eligible, Red > 20 TPY
D9	Wilm	Heater	200	37.5	40	5	4.7	22	20.5	Not Eligible, Red > 20 TPY
D247	Wilm	Heater	82	8	43	5	0.9	18	3.3	Not Eligible >25 ppmv
D248	Wilm	Heater	50	9.4	43	5	1,1	18	3.9	Not Eligible >25 ppmv
D249	Wilm	Heater	29	4.2	43	5	0.5	18	1.7	Not Eligible >25 ppmv
D146	Wilm	Heater	69	23.3	134	5	0.9	18	3.1	Not Eligible, Red > 10 TPY
D33	Wilm	Heater	252	22.6	17	5	6.5	22	28.6	Eligible < Table 2
D388	Wilm	Heater	147	15.2	16	5	4.7	22	20.8	Table D-1 and D-2 Eligible
D214	Wilm	Heater	56	2.9	17	5	0.8	18	3.1	Eligible < Table 2
D215	Wilm	Heater	36	2.6	17	5	0.8	18	2.8	Eligible < Table 2
D216	Wilm	Heater	31	2	17	5	0.6	18	2.2	Eligible < Table 2
D217	Wilm	Heater	31	4.6	17	5	1.4	18	4.9	Eligible < Table 2

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D158	Wilm	Heater	204	9.4	84	5	0.6	22	2.5	Not Eligible >25 ppmv
D386	Wilm	Heater	48	2.2	19	5	0.6	18	2.1	Eligible <25 ppmv
D387	Wilm	Heater	71	3.9	19	5	1	18	3.6	Table D-2 Eligible
D120	Wilm	Heater	45	8.9	63	5	0.7	18	2.6	Not Eligible >25 ppmv
D157	Wilm	Heater	49	8.7	63	5	0.7	18	2.5	Not Eligible >25 ppmv
D218	Wilm	Heater	60	7.2	26	5	1.4	18	5.1	Not Eligible >25 ppmv
D384	Wilm	Heater	48	2.2	18	5	0.6	18	2.2	Table D-1 and D-2 Eligible
D385	Wilm	Heater	24	1.1	18	5	0.3	18	1.1	Table D-1 and D-2 Eligible
D1122	Wilm	Boiler	140	1.9	7	5	1.3	7.5	2	Table D-1 and D-2 Eligible
D777	Wilm	SMR Heater	146	5.4	7	5	3.7	7.5	5.6	Table D-1 and D-2 Eligible
D250	Wilm	Heater	35	2.3	31	9	N/A	N/A	N/A	N/A
D770	Wilm	Heater	63	1.6	7	5	1.1	18	4	Table D-1 and D-2 Eligible

Table H-4. Torrance Refinery Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

TORRANCE REFINERY									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D803	Boiler	309	203.5	116.8	5.0	8.7	N/A	N/A	Not Eligible, Red > 20 TPY
D805	Boiler	291	141.8	35.2	5.0	20.1	N/A	N/A	Not Eligible, Red > 20 TPY
D151	FCCU	-	100.7	10.3	2.0	19.6	8.0	78.2	Eligible
C164	CO Boiler	464	-	-	2.0	-	8.0	-	Eligible
D2320	FCC SU Heater	132	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D913	Heater	457	48.5	16.3	5.0	14.9	N/A	N/A	Not Eligible, Red > 20 TPY
D914	Heater	161	16.3	16.3	5.0	5.0	N/A	N/A	Not Eligible, Red > 20 TPY
D917	Heater	91	23.9	60.6	5.0	2.0	N/A	N/A	Not Eligible, Red > 10 TPY
D918	Heater	91	24.5	67.6	5.0	1.8	N/A	N/A	Not Eligible, Red > 10 TPY
D120	Heater	126	21.0	70.0	5.0	1.5	N/A	N/A	Possibly Eligible
D930	Heater	129	23.6	51.2	5.0	2.3	N/A	N/A	Not Eligible, Red > 20 TPY
D83	Heater	67	16.7	52.5	5.0	1.6	N/A	N/A	Not Eligible, Red > 10 TPY
D84	Heater	67	16.2	53.0	5.0	1.5	N/A	N/A	Not Eligible, Red > 10 TPY
D85	Heater	74	15.4	43.2	5.0	1.8	N/A	N/A	Not Eligible, Red > 10 TPY
D931	Heater	73	13.8	51.2	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY

TORRANCE REFINERY									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D269	Heater	107	10.6	43.1	5.0	1.2	18.0	4.4	Possibly Eligible
D920	Heater	108	7.1	22.4	5.0	1.6	18.0	5.7	Table D-2 Eligible
D1239	Boiler	340	8.0	7.2	5.0	5.6	7.5	8.4	Table D-1 and D-2 Eligible
D1236	Boiler	340	4.9	5.8	5.0	4.3	7.5	6.4	Table D-1 and D-2 Eligible
C626	Vapor Incinerator	60	7.2	45.4	30.0	4.8	40.0	6.4	Possibly Eligible
D949	Heater	40	3.5	23.8	9.0	1.3	N/A	N/A	No Table 2 Limit
D234	Heater	60	0.5	13.1	5.0	0.2	18.0	0.7	Table D-1 and D-2 Eligible
D235	Heater	60	1.0	13.1	5.0	0.4	18.0	1.4	Table D-1 and D-2 Eligible
D950	Heater	64	1.4	11.7	5.0	0.6	18.0	2.2	Table D-1 and D-2 Eligible
C686	Vapor Incinerator	4	2.8	38.0	30.0	2.2	40.0	3.0	Possibly Eligible
D927	Heater	17	3.0	11.7	9.0	2.3	N/A	N/A	No Table 2 Limit
D231	Heater	60	0.4	13.1	5.0	0.2	18.0	0.6	Table D1 and D-2 Eligible
D232	Heater	60	0.5	13.1	5.0	0.2	18.0	0.6	Table D-1 and D-2 Eligible
D928	Heater	17	2.6	11.7	9.0	2.0	N/A	N/A	No Table 2 Limit
D929	Heater	21	0.4	27.1	9.0	0.1	N/A	N/A	No Table 2 Limit
D1403	Heater	21	0.4	27.1	9.0	0.1	N/A	N/A	No Table 2 Limit
C687	Vapor Incinerator	4	1.2	38.0	30.0	0.9	40.0	1.3	Possibly Eligible
C952	SRU/TGI	100	15.9	19.6	30.0	24.3		N/A	Not Eligible, Meets Table 1 Limit

Table H-5. Ultramar Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

ULTRAMAR (VALERO)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D36	Wilm	FCCU	-	87.7	23.3	2	7.5	8	30.1	Not Eligible
D38	Wilm	FCC SU Heater	100	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D74	Wilm	Heater	258	30.9	38.4	5	4	22	-	Not Eligible, Red > 20 TPY
D3	Wilm	Heater	159	17.2	30.8	5	2.8	22	12.3	Possibly Eligible
D6	WIlm	Heater	136	13.5	19	5	3.6	22	15.6	Table D-1 and D-2 Eligible
D52	Wilm	Heater	36	18.9	96	9	1.8	N/A	N/A	No Table 2 Limit
D22	Wilm	Heater	95	9.5	29.8	5	1.6	18	5.7	Possibly Eligible
D12	Wilm	Heater	144	8.8	26.7	5	1.7	22	7.3	Possibly Eligible
D53	Wilm	Heater	68	8.2	23.2	5	1.8	18	6.4	Table D-2 Eligible
D8	Wilm	Heater	49	6.3	34.4	5	0.9	18	3.3	Possibly Eligible
D98	Wilm	Heater	57	5.8	23.1	5	1.2	18	4.5	Table D-2 Eligible
D768	Wilm	Heater	110	5.9	10.3	5	2.9	18	10.3	Table D-1 and D-2 Eligible
D1550	Wilm	Boiler	245	5.4	5.2	5	5.2	7.5	7.7	Table D-1 and D-2 Eligible
D73	Wilm	Heater	30	4.8	20.7	9	2.1	N/A	N/A	No Table 2 Limit
D59	Wilm	Heater	26	3.2	33.5	9	0.9	N/A	N/A	No Table 2 Limit
D60	Wilm	Heater	30	3.6	26.2	9	1.2	N/A	N/A	No Table 2 Limit
D429	Wilm	Heater	30	1	6.3	5	0.8	22	3.5	Table D-1 and D-2 Eligible
D430	Wilm	Heater	200	6.5	6.3	5	5.2	22	22.7	Table D-1 and D-2 Eligible
D9	Wilm	Heater	20	2.5	25.7	9	0.9	N/A	N/A	No Table 2 Limit

ULTRAMAR (VALERO)											
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D378	Wilm	Boiler	128	2.6	5.6	5	2.3	7.5	10.2	Table D-1 and D-2 Eligible
C1260	Wilm	SRU/TGI	36	3	89.8	30	1	N/A	N/A	No Table 2 Limit
D377	Wilm	Boiler	39	0	0	5	0	7.5		Not Eligible, Meets Table 1 Limit
D1669	Wilm	Gas Turbine	342	3.2	2.1	2	3.1	2.5	3.8	Possibly Eligible
D179	Asphalt Plant	Heater	15.4	0.03	13.5	9	0.01	N/A	N/A	N/A
D13	Asphalt Plant	Heater	19.3	2.9	20.7	9	1.6	N/A	N/A	N/A
D63	Asphalt Plant	Boiler	14.5	1.9	31	5	1.6	N/A	N/A	N/A
D64	Asphalt Plant	Boiler	14.5	0	0	5	0	N/A	N/A	N/A

Table H-6. Air Products Emissions Based on PR 1109.1 Table 1 and Table 2

AIR PRODUCTS								
Device ID	Facility	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 2 NOx Limit	Conditional Limit Eligibility
D30	Carson	SMR Heater	764	16.5	3.9	5	7.5	Not Eligible, Meets Table 1 Limit
D38	Wilmington	SMR Heater	785	21.6	5.7	5	7.5	Eligible for Table 2 Limit
D367	Torrance	SMR Heater	527	131.1	53.4	5	7.5	Not Eligible for Table 2 Limit
D925/ D926	Torrance	SMR Heater/GTG	1,247	29.9	4.4	5	N/A	N/A

Table H-7. Air Liquide Emissions Based on PR 1109.1 Table 1 and Table 2

AIR LIQUIDE								
Device ID	Facility	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 2 NOx Limit	Conditional Limit Eligibility
D24	El Segundo	SMR Heater	780	20	3.7	5	7.5	Not Eligible, Meets Table 1 Limit

Table H-8. Lunday-Thagard Emissions Based on PR 1109.1 Table 1 and Table 2

LUNDAY THAGARD (WORLD OIL)							
Device ID	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 2 NOx Limit	Conditional Limit Eligibility
D19	Heater	6	0.87	12	9	N/A	N/A
D20	Heater	39.0	12.2	49	9	N/A	N/A
D84	Heater	5.5	0.74	58	9	N/A	N/A
D214	Boiler	29.4	0.10	7.9	5	N/A	N/A
D231	Boiler	39.9	0.78	7.4	5	N/A	N/A
C97	Vapor Incinerator	14	11.2	88	30	40	Not Eligible
C105	Vapor Incinerator	1.4	0.56	101	30	40	Not Eligible

Table H-9. Eco-Services Emissions Based on PR 1109.1 Table 1 and Table 2

ECO-SERVICES							
Device ID	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 2 NOx Limit	Conditional Limit Eligibility
D1	Sulfuric Acid Furnace	150	16.5	22	30	N/A	N/A
D98	SU Heater	50	21.6	49	5	N/A	Exempt (o)(6)
D139	SU Boiler	49	0.74	29.6	5	N/A	Exempt (o)(6)
C126	Flare	1.09	0.1	-	20	N/A	Exempt (o)(8)

Table H-10. AltAir Emissions Based on PR 1109.1 Table 1 and Table 2

ALTAIR							
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Representative NOx (ppmv)**	**Table 1 NOx Limit**	**Table 2 NOx Limit**	**Conditional Limit Eligibility**
D44	Heater	12.8	-	2.7	9	N/A	Meets Table 1 Limit
D45	Heater	5	-	2.7	9	N/A	Meets Table 1 Limit
D46	Heater	28	0.32	2.7	9	N/A	Meets Table 1 Limit
D374	Boiler	44.5	6.2	71.6	5	7.5	Not Eligible
D375	Boiler	44.5	0	-	5	7.5	Not Eligible
D376	Boiler	65.9	8.4	105.1	5	7.5	Not Eligible
C175	Vapor Incinerator	10	3.7	110	30	N/A	N/A
D691	Vapor Incinerator	8	0	-	30	N/A	N/A
C882	Vapor Incinerator	1.2	0.12	-	30	40	Exempt (o)(9)
C887	Vapor Incinerator	1.2	0.25	-	30	40	Exempt (o)(9)
C531	Vapor Incinerator	30	4.7	68.2	30	40	Not Eligible
D569	Vapor Incinerator	8	-	-	30	40	Not Eligible
D677/D679	Gas Turbine/Duct Burner	140	0	1.7	2	2.5	Eligible for Table 2, Unit has permit limit of 2.5 ppmv

APPENDIX I RESPONSE TO COMMENTS

Public Workshop Comments

Staff held a Public Workshop on September 1, 2021 to provide a summary of PR 1109.1, PR 429.1, PAR 1304, PAR 2005, and PRR 1109. The following is a summary of the comments received on PR 1109.1 and staff's responses.

Commenter #1: Chris Chavez– Coalition for Clean Air

The commenter expressed concern regarding the flexibility options in PR 1109.1 and the legal ramifications for violations if not meeting the goals set out in the plans.

Staff Response to Commenter #1:

PR 1109.1 is estimated to cost the petroleum refineries between $179 million to $1 billion to comply and will require approximately 75 SCR installations, 25 SCR upgrades and many burner replacements. Staff worked to craft a rule that would maximize emission reductions but allow flexibility so the costs for projects with high cost and low emission reductions could be used elsewhere. Alternate compliance plans provide flexibility for affected facilities in deciding which projects are more or less cost-effective to achieve greater emission reductions that would be achieved if each unit was operated at the BARCT NOx limit. Under B-Plan and B-Cap, each unit will be required to take a NOx concentration limit on the permit.

Violations of the rule are subject to penalties and fines under the Health and Safety Code. There are multiple dates in PR 1109.1 that must be met by the owner or operator of the facility. In addition, the emission limits and each condition in the Permit to Construct and Permit to Operator are enforceable as well as the approved I-Plan, B-Plan, and B-Cap.

Commenter #2: Julia May – Communities for a Better Environment

Commenter stated that based on the data in the staff report, it shows that 88 percent of the equipment at facilities subject to the RECLAIM is not at BARCT. This shows the RECLAIM program failed and modern controls were not installed. Refineries are getting a good deal with the flexibility in the schedule in PR 1109.1. All equipment should be required to meet the most stringent NOx levels. The expected emission reductions are lower due to the flexibilities provided and an extra 1 tpd of reductions with the most stringent standards can be achieved.

Staff Response to Commenter #2:

While a number of facilities under the RECLAIM program did not install control equipment on all of their equipment, they still complied with the requirements and program elements of RECLAIM. As a command-and-control rule, PR 1109.1 will require NOx limits on each affected unit with a majority required to install effective NOx control equipment to meet the stringent emission standards. With regards to flexibility in the schedule, PR 1109.1 establishes various implementation options for facilities to meet emission reduction targets at different deadlines. The implementation schedules account for the variability that could occur during the process (e.g., permitting time) and reflect realistic planned turnaround times to properly schedule when projects can be completed. As such, the implementation schedules recognize the time needed to design, engineer, budget, order, deliver, logistics, install, and commission, in order to properly meet a scheduled turnaround or target deadline. Staff has provided additional time and flexibility in the schedules for implementing the emission control projects, including provisions for an extension of the schedule.

The flexibilities in the B-Plan and B-Cap are required to achieve the emission reduction goals in PR 1109.1, due to the complexity of the projects and the total number of equipment to be retrofitted within different class and categories of equipment in the rule. The I-Plan provides the flexibility to align the projects with the facility's scheduled turnarounds to avoid additional cost, downtime, and potential disruptions to the fuel supply.

Commenter #3: Emily Spokes – member of the community

Commenter expressed concerns for the people who are working at the refineries as being at the front line of enduring loss.

Staff Response to Commenter #3:

Staff appreciates the comment and anticipates the outcome of the proposed project will provide an air quality and public health benefit to the regional air quality, local communities, as well as onsite workers.

Commenter #4: Oscar Espino Padron– Earthjustice

Commenter expressed concern regarding the flexibility provided to the refineries through alternative plans under PR 1109.1 and stated that there is a need for stronger guardrails to ensure refineries are complying with the established targets. The commenter stated that PR 1109.1 includes no clear language or listed penalties in this regard. The commenter requested a mechanism for the agency to reassess whether the 9ppmv compliance deadline for boilers and process heaters can be moved up if emerging technologies are available sooner than the 10-year timeframe in the PR 1109.1. The commenter also expressed concerns related to the inconsistency of start-up and shutdown provisions in the rule with the Clean Air Act.

Staff Response to Commenter #4:

Please see the Response to Comment 1-1 regarding plan flexibility and enforcement penalties if a facility fails to meet the targets or deadlines. For the emerging technology, staff intends to conduct a technology assessment to evaluate the progress of the burner technologies to achieve levels at or below 9 ppmv but does not intend to require the transition to the emerging technologies on an earlier timeframe. Staff worked to develop a compliance schedule that will work for each of the facility's future turnaround schedules and any unanticipated changes to a future implementation schedule would be challenging. While staff does not intend to shorten the ten-year effective date for the burner replacement, PR 1109.1 does include a shorter timeframe for when the facility has to track the cumulative replacement of the burners. Cumulative burner replacement is what triggers the 9 ppmv concentration limit and is tracked starting five years from rule adoption. The five-year timeframe is needed to allow units not meeting 40 ppmv to retrofit to meet the initial 40 ppmv limit. After five years, any burner replacement is considered as part of the cumulative burner replacement; therefore, any facility that replaces more than 50 percent of their burners starting after five years will have to transition to 9 ppmv as soon as 10 years from rule adoption. This provision is to prevent a facility from replacing the burners in their boilers and heaters before the 10-year effective date in order to delay installing burners to meet the 9 ppmv NOx limits.

For the startup and shutdown comment, please see staff's response in the Staff Report for PR429.1.

Commenter #5: Byron Chan – Earthjustice

Commenter asked about the timeline that staff considers for issuing the permits to construct by AQMD as the reference in determination of compliance date in I-Plan.

Staff Response to Commenter #5:

Engineering staff estimates it will take 12 to 18 months from submittal of a complete permit application to evaluate and issue a permit to construct. The proposed rule provides contingency provisions if the permit takes longer to issue which could impede in the project's ability to be included in next planned turnaround.

Commenter #6: Michael Carroll – Latham & Watkins LLP

Commenter stated that in order to meet the stringent standards and target reductions, rule compliance flexibility and extended timelines are necessary.

Staff Response to Commenter #6:

Staff supports compliance flexibility with conditional limits and implementation options in order to ensure the stringent BARCT limits will be achieved.

Comment Letters

Comment Letter #1

NANETTE DIAZ BARRAGÁN
44TH DISTRICT, CALIFORNIA
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COMMITTEE ON ENERGY AND COMMERCE
SUBCOMMITTEES:
HEALTH
ENVIRONMENT AND CIMATE CHANGE
ENERGY

COMMITTEE ON HOMELAND SECURITY
SUBCOMMITTEES:
BORDER SECURITY, FACILITATION, AND OPERATIONS
CHAIRWOMAN

CONGRESSIONAL HISPANIC CAUCUS
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701 E. CARSON STREET
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8650 CALIFORNIA AVENUE
SOUTH GATE, CA 90280

205 S. WILLOWBROOK AVENUE
COMPTON, CA 90220

August 27, 2021

Governing Board
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Dear South Coast Air Quality Management District Governing Board:

I am writing in regard to the South Coast Air Quality Management District (SCAQMD) Governing Board's consideration to adopt Proposed Rule 1109.1. By reducing nitrogen oxide (NOx) emissions by an estimated seven to nine tons per day, this rule would have a significant impact on improving regional air quality and protecting public health. I respectfully urge the SCAQMD Governing Board to commit to the following:

Voting to adopt Proposed Rule 1109.1 by the November 2021 Governing Board meeting. At the December 2020 Governing Board meeting, the vote was proposed for June 2021. Since then, the vote has been postponed twice more and is now scheduled for November 2021. During this time, NOx emissions from refineries have continued to disproportionately affect frontline communities of color, including in Carson and Wilmington, resulting in elevated rates of asthma, cancer, and other environmental health impacts. 1-1

Include a 2 parts per million (ppm) NOx standard for all large boilers and heaters within Proposed Rule 1109.1. By applying this standard to boilers and heaters which burn more than 40 million British Thermal Units (BTUs) of gas per hour, the rule would achieve a 95% reduction in regional NOx emissions. Currently, the refineries in Carson and Wilmington, California alone emit approximately 4.5 tons of NOx emissions per day. A strong rule with a 2 ppm standard will have tremendous impact throughout the region, and particularly in the communities most harmed by environmental inequities. 1-2

No exemptions for refineries during startup, shutdown, and malfunction periods. Refineries must be held accountable to the standards of Proposed Rule 1109.1 during non-compliance periods that are a result of inadequate equipment maintenance, operator error, or other negligence. These exemptions would provide an incentive to pollute without limitations during equipment startup and shutdown. 1-3

Proposed Rule 1109.1 is the Governing Board's opportunity to correct decades of environmental harm and devastating health impacts caused by the lack of strong air quality regulations and the 1-4

Rep. Barragán
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necessary enforcement. The equipment upgrades required via best available retrofit control technology are cost effective and overdue. Implementing the rule will address some of the shortcomings of the Regional Clean Air Incentives Market (RECLAIM) Program by ensuring refineries invest in the equipment required to reduce emissions. 1-4 (con'td)

As the Representative of California's 44th Congressional District, I urge the Governing Board to thoroughly consider the public's health by voting to adopt a strong Proposed Rule 1109.1 as soon as possible. Thank you for your attention to this urgent matter.

Sincerely,

Nanette Diaz Barragán

Nanette Diaz Barragán
Member of Congress

Staff Response to Commenter Letter #1:

Response to Comment 1-1:

Staff is working to keep the rule development schedule on track for the Governing Board to consider approval of PR 1109.1, and companion rules at the November 5, 2021 Governing Board meeting.

Response to Comment 1-2:

For boilers and heaters ≥40 MMBtu/hr, staff originally proposed a BARCT limit of 2 ppmv based on the combination of new Ultra-Low NOx Burners (ULNB) and Selective Catalytic Reaction (SCR) (Working Group meeting #9 held on December 12, 2019). Industry stakeholders raised concerns regarding the ability to replace existing Low-NOx Burners (LNBs) with ULNBs since many of the units are older and not designed for ULNBs which require more spacing. The recommended American Petroleum Institute (API) guidelines were cited for refinery fired heaters (API 560) and burners (API 535) that include heat density and minimum burner spacing for optimal operation and safety. A higher heat density (MMBtu/hr/ft^2) can result in higher flame temperatures and therefore increase NOx emissions. If burner spacing is not adequate, this can lead to flame interactions or coalescing which results in increased NOx emissions and potential impingement of the tubes. While the guidelines are not requirements, not operating within guidelines is considered "suboptimal" which can impact burner NOx performance. Third party engineering consultants, Norton Engineering, concluded in their report that under conditions that are optimal, 30 ppmv NOx can be achieved with ULNB, but suboptimal burner installations will achieve 40 – 50 ppmv. For those ULNB applications achieving 50 ppmv, the 2 ppmv will not be technically feasible even with 95% reduction from SCR. The report specifically noted:

> "*For older heaters designed with prior burner technologies the above-mentioned criteria (flame length, heat flux, fuel conditioning, burner spacing, turndown) are rarely achieved when upgrading to newer ULNB. In situations where an existing heater is constrained, as mentioned earlier, upgrading to ULNB may not achieve the lowest NOx emission level demonstrated by the technology.*"

Two refineries in recent years experienced these highlighted issues when attempting to convert the existing burners to ULNB. As a result, both refineries retracted their projects over safety concerns. Because of these ULNB challenges, staff re-focused on the SCR technology, which is a proven, highly effective, reliable option in lowering the NOx emissions from larger heaters and boilers.

Regarding SCR, Norton was not confident that single bed SCR would achieve the 2 ppmv NOx level stating, "*SCR designs can achieve 92 to 94% NOx reduction in a single catalyst bed with NH3 slip in the 5 to 10 ppmv range*." The report acknowledged that "*multiple catalyst beds, often times with an additional ammonia injection grid between the beds, is required to achieved NOx reduction levels greater than ~94%. The addition of catalyst beds is the most effective means of ensuring that SCR systems can reliably achieve sub 10 ppmv NOx emission levels*."

Taking the advice provided by the consultants, staff conducted a further technology search and concluded that there are alternative pathways that do not involve installation of ULNB in those older units where space and safety could be a problem. Such alternatives could be adding another stage or layer of catalyst in the SCR reducing NOx emissions down to 2 ppmv (Working Group Meeting #17). However, in doing so, there is an increase in cost for additional equipment, ammonia, and installation due to the higher footprint of the two-stage SCR compared to the single-stage installation. Stakeholders indicated costs could increase by over 80 percent.

Facilities submitted the revised cost data, and staff reassessed proposed BARCT limits for equipment categories that were affected such as boilers and heaters ≥ 40 MMBtu/hr. If cost data was not provided, staff used facilities' suggested cost of 80% increase of single-stage reactor for two-stage SCR. Revised cost estimates for boilers ranged from $2 MM to $70 MM and revised cost estimates for heaters ranged from $5 MM to $244 MM to achieve 2 ppmv with a two-stage SCR, ULNB single stage, or unit replacement. Therefore, the proposed requirement to meet 2 ppmv with the revised cost data was determined to be not cost-effective. Using the single-stage SCR, however, could technically achieve 5 ppmv, and the revised cost estimates were much less due to less equipment, less ammonia, and less space challenges. The revised cost estimates for boilers ranged from $10 MM to $40 MM, and revised cost estimates for heaters ranged from $2 MM to $45 MM to achieve 5 ppmv with a single stage SCR.

California Health & Safety Code Section 40920.6(a)(3) requires a calculation of the incremental cost effectiveness for potential control options by determining cost differences divided by the difference in emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option. As such, the comparison of the 5 ppmv NOx limit to the more stringent control option at 2 ppmv was evaluated, and it was determined to be not cost effective. For boilers and heaters, the incremental cost effectiveness from 5 ppmv to 2 ppmv was determined to be, respectively, $159,000 and $656,000 per ton of NOx reduced. Thus, to propose the more stringent potential control option at 2 ppmv was determined to be not cost effective and not recommended as the BARCT limit for these categories. However, installing single stage SCR on an existing unit with LNBs still proves to be effective and reducing NOx emissions and cost-effective to achieve a BARCT level of 5 ppmv and is recommended by staff.

Response to Comment 1-3:

Please see staff's response in the Staff Report for PR429.1.

Response to Comment 1-4:

Transitioning facilities from the RECLAIM program to a command-and-control regulatory program will require all units under RECLAIM to meet NOx emission limits that are representative of BARCT or BARCT in the aggregate. Implementation of PR 1109.1 provides assurance that NOx reductions will occur at petroleum refineries and facilities with related operation to petroleum refineries.

Comment Letter #2a:

This email, or a version similar to this email, was received by the Clerk of the Board from over 1,000 members of the public.

> Dear c/o Clerk of Board South Coast Air Quality Management Governing Board,
>
> I urge you to adopt Refinery Rule 1109.1 to help our region meet air-quality standards and protect public health.
>
> Southern California has the worst ground-level ozone pollution in the nation. It threatens the health of residents with a range of harms, including asthma, diminished lung function and premature death. These harms cause negative socioeconomic impacts such as increased health care costs, missed workdays and school absences.
>
> Petroleum refineries are a major source of ozone pollution. State law requires life-saving pollution control technologies to be installed on large emissions sources. But refineries have avoided making these upgrades to save themselves millions of dollars — and they continue to delay. Refinery Rule 1109.1 would require them to finally install controls on equipment such as large boilers and heaters, which will create jobs as well as improve public health.
>
> Communities living near refineries can't afford to wait any longer. It's time to adopt a strong Refinery Rule 1109.1 to secure maximum emissions reductions at petroleum refineries as quickly as possible.

Staff Response to Comment Letter #2a:

Staff is working to keep the rule development schedule on track for the Governing Board to consider approval of PR 1109.1, and companion rules, at the November 5, 2021 Governing Board meeting. The purpose of PR 1109.1 is to require emission reductions on all emission sources at the petroleum refineries, including large boilers and heaters. The Socioeconomic Assessment concluded the proposed project would generate jobs and result in benefits to public health in terms of avoiding premature deaths, asthma attacks, and loss of workdays.

Comment Letter #2b:

SIERRA CLUB

Monday, August 30, 2021

Clerk of the Board,
South Coast AQMD,
21865 Copley Drive
Dimond Bar, CA 91765-4178

South Coast Air Quality Management District Governing Board Members:

The Sierra Club submits the following 560 digital signatures on the behalf of our members and supporters, urging the South Coast Air Quality Management District to implement a strong Refinery Rule (1109.1).

Petition Language:

Dear Governing Board Members:

We submit this letter in support of Refinery Rule 1109.1, which would bring our region closer to meeting air quality standards to protect public health.

Our region continues to have the worst ground-level ozone pollution in the nation. This pollution threatens the health of residents in the region with a range of harms, including asthma, diminished lung function, and premature death. These harms, in turn, cause negative socio-economic impacts, such as increased health care costs, missed workdays, and school absences.

Petroleum refineries are a major source of ozone-causing pollution. For decades, refineries have avoided installing available life-saving pollution controls on hundreds of pieces of equipment, such as large boilers and heaters. As a result, refineries have saved millions of dollars. Refinery Rule 1109.1 would require refineries to finally install available controls on equipment that will improve public health and create jobs.

We encourage you to adopt a strong Refinery Rule 1109.1 that secures the maximum amount of emissions reductions at petroleum refineries as quickly as possible. Refineries have had five years to install these pollution controls but have delayed making these necessary investments and are currently lobbying to keep delaying indefinitely. Communities living near refineries have waited for far too long and cannot afford to wait any longer.

Staff Response to Comment Letter #2b:

Staff appreciates the comment. PR 1109.1 is needed to reduce NOx emissions, which is an ozone precursor. Three of the five major petroleum refineries are located in the AB 617 communities of Wilmington, Carson, and Long Beach. Emission reductions will help reduce emissions in these communities and communities surrounding the other refineries. Staff is working to keep the rule development schedule on track for the Governing Board to consider approval of PR 1109.1, and companion rules, at the November 5, 2021 Governing Board meeting.

Comment Letter #3:

Valero

September 10, 2021

Ms. Susan Nakamura
Assistant Deputy Executive Officer, Planning & Rules
South Coast Air Quality Management District
Diamond Bar, CA 91765
Via electronic mail at Snakamura@aqmd.gov

Re: Proposed Rule 1109.1

Dear Ms. Nakamura,

Ultramar Inc. (Valero) submits the following comments on South Coast Air Quality Management District (SCAQMD or District) Proposed Rule 1109.1, based on the September 1 Workshop version of the rule and the accompanying preliminary draft staff report. Valero operates a petroleum refinery in Wilmington, California and would be subject to the proposed rule as adopted by the District Governing Board. Valero supports the District's efforts to reduce emissions in the South Coast Air Basin (basin) and looks forward to continuing working with the District to identify feasible, cost-effective solutions.

The purpose of the proposed rule is to establish current and future best available retrofit control technology (BARCT) for various NOx emitting equipment at the five refineries in the basin and associated industries, while transitioning these facilities from the current regulatory scheme established by NOx RECLAIM.

We appreciate the tremendous effort staff has put into this complex task and the time that staff has taken to try to understand our particular issues. Valero is the smallest refinery in the basin in both volume and footprint and has unique constraints in constructing additional controls. With the very limited available space at the refinery, we must carefully engineer any add-on controls for affected equipment, which is a time and resource-intensive exercise unique to Valero's operations. Staff has included several provisions in the proposed rule that are very helpful, such as recognizing current BARCT (Interim Limits) and the need to schedule turnarounds to install controls to implement future-effective BARCT.

However, Valero still has several issues with the current proposal, most of which relate to the proposed fluid catalytic cracking unit (FCCU) BARCT of 8 ppm for some units with existing controls and 2 ppm for others.

RECLAIM

First, we do not believe staff has properly considered the baseline for purposes of determining BARCT for FCCUs. The proposal begins with a baseline that looks at the state of equipment and controls at each facility and largely ignores the fact that facilities took efforts to comply with the RECLAIM Program since its 3-1

Wilmington Refinery • Ultramar Inc., a Valero Company
2402 E. Anaheim • Wilmington, CA 90744 • Telephone (562) 491-6877

inception in 1993 and the multiple methods taken to achieve emission targets. The approach taken does not transition from existing RECLAIM, rather it establishes a new rule as though no current BARCT regulations exist. No effort is made in the proposed rule to deconstruct RECLAIM, rather, it completely overlooks the current BARCT strategies that comprise RECLAIM. This is largely due to the misconception that RECLAIM failed because not all equipment at refineries has control equipment installed. This was never a metric of RECLAIM. The success of RECLAIM was meant to be measured by the overall programmatic reduction in mass emissions that were equivalent to those that would be achieved by command and control rules and did not specify specific controls[1]. Participation in the program through RECLAIM trading credit purchases essentially subsidized installation of controls at other facilities by providing funds to offset the cost to install control equipment. Ignoring the actions facilities took to comply with RECLAIM puts many RECLAIM facilities that relied on the program as designed and implemented at a disadvantage as compared to others, depending on how a facility opted to comply.

BARCT under RECLAIM was properly implemented through a very involved process of looking at all of the equipment under the program, determining appropriate BARCT, including future-effective BARCT for each equipment category, estimating the mass emissions reductions that would be achieved through the implementation of BARCT, and then converting the total mass emission reductions into facility mass emissions caps and shaving those emission caps over the proper timeframe calculated to implement BARCT. Each facility could then properly choose the manner in which they would achieve mass emission reduction targets at their respective facilities. They could either put controls on the identified equipment category, control emissions from other equipment at the facility, purchase emission credits from other facilities that over-controlled, or a combination of the above. In the end, whichever method was chosen, the facility that met the ever-declining emissions cap, met BARCT for the facility and should be credited with meeting BARCT for its equipment. Staff's methodology of establishing new BARCT limitations and the cost of those controls largely ignores all of the investments made to meet the legal and regulatory requirements of BARCT unless a control device was installed. Again, this arbitrarily places some facilities at a distinct disadvantage over others. 3-1 (cont'd)

The RECLAIM market driven compliance mechanism has been effective and enabled some facilities to develop new BARCT that may not have been achieved without allowing others to invest in control technology development through the purchase of credits. The purchase of credits helped to subsidize controls for other RECLAIM participants. A prime example of this is the recently adopted Rule 1117. The facilities attest that the controls were much too cost prohibitive to install without the ability to sell credits to offset the installations costs of these controls. These types of accomplishments must be accounted for in any transition from RECLAIM.

Valero, during its many years of operation under the RECLAIM program, opted to comply using a combination of allowed methodology and as one method, chose to purchase RECLAIM Trading credits. As

[1] See, e.g., Final Staff Report for the Regional Clean Air Incentives Market, October 1993, at page 1-1:
"The goal of RECLAIM is to achieve the emission reduction objectives for the Basin by providing facility operators with the flexibility to choose how to make emission reductions, thereby lowering compliance costs and providing incentives for the development and implementation of air pollution control technologies. Implementation of RECLAIM will reduce emissions from sources in the program to the same extent that they would be required to reduce emissions through implementation of existing regulations and the Air Quality Management Plan (AQMP). RECLAIM is designed to ensure that *the program achieves equivalent emission reductions*, an equal or greater level of enforcement, lower implementation costs, fewer job impacts, and no adverse public health impacts, compared to the existing program." (emphasis added)

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proposed, Rule 1109.1 does nothing to recognize this valid compliance mechanism and puts Valero at an economic disadvantage as compared to other refineries that would be subject to the new rule, when they relied on a valid regulatory program for many years. For instance, when conducting the required cost element of BARCT for FCCUs, the District simply estimates the cost of controls for the facility, without accounting for either the overall reductions the facility made over the years, including through the purchase of credits, and estimates costs of additional selective catalytic reduction (SCR) as though Valero has done nothing to control emissions. This cost is then compared to other FCCUs where the facility opted to partially control emissions through add-on controls. The result is that the District would have Valero pay twice for emission controls (credits plus SCR), while others pay only once (for SCR). To remedy this inequity, the District should either start with an assumption of the BARCT control that the District calculated when setting the RECLAIM shave with which Valero has complied or add the cost of the credits Valero purchased to the cost of the controls the District now seeks to have Valero install when conducting the cost-effectiveness evaluation. 3-1 (cont'd)

BARCT for FCCUs

To further compound the disproportionate effect of the proposed rule, the District is seeking to establish BARCT for FCCUs to be controlled under PR 1109.1 at 2ppm NOx averaged over 365 days. Valero does not believe this is achievable in a cost-effective manner.

BARCT is an emissions limitation established for a class or category of sources under California Health & Safety Code Section 40406. The District has long considered the category of source as FCCUs. In fact, the rulemaking has for the past few years centered on this principle.

The equipment category is FCCUs. There are only 5 units in the equipment category. In this source category, one FCCU is controlled by an SCR that has been installed and is reportedly on average meeting a 2 ppm limit. Two other units have SCRs installed as controls but meet an 8 ppm limit. Another has filed an application to install an SCR at 2 ppm. Rather than setting one unified emission limit for all FCCUs, the District is proposing to break up this very small equipment category into even smaller segments, essentially establishing individual emission limits for each facility. That is inconsistent with regulatory requirements under Health and Safety Code, Division 26, Part 3 (and similar provisions) for establishing BARCT, and does not meet the District's mandates to establish emissions limits for a source category. The District staff would have the unit currently at 2 ppm, remain at 2 ppm, the two units that are able to operate at 8 ppm would remain at 8 ppm, and the other two units, which currently do not have an SCR, would have to meet a 2 ppm limit. 3-2

To justify splitting this category up unit by unit, the District does a cost analysis on the four units that would have to do additional controls, and then throws half of the units out of the cost equation, labeling them "outliers" without providing a statistical basis for how this was determined. This is not an objective, scientific determination; rather, this is picking and choosing controls in order to maximize total emission reductions. There is no equitable or technically supportable way to divide this source category in a manner consistent with the Health and Safety Code (as referenced above), and thus should be looked at in the way it was intended, as a whole source category of five FCCUs, and BARCT should be established for the category as a whole. A proper BARCT analysis would look at one emission limitation for the entire class and analyze the cost for all units to comply, thus setting the BARCT limitation at the level that meets all the technological and cost requirements to establish BARCT. Any division of the category by the District places some facilities in a disadvantage compared to others, and has the District picking winners and losers rather than objectively

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establishing BARCT and requiring all affected facilities to meet that limit. By arbitrarily splitting the category into single facilities and completely discounting the considerable investments made to achieve RECLAIM program goals through purchase of credits, the proposed FCCU BARCT assessment artificially deflates the costs associated with installation of controls and meanwhile creates competitive disadvantages for the facilities that must bear these costs. 3-2 (cont'd)

Implementation Schedule

Valero appreciates staff working with the refineries to understand the complexities of engineering and installing equipment in setting BARCT deadlines. This affects technical feasibility and is a crucial element to consider in establishing BARCT. However, we are still concerned that the schedule for FCCUs is not achievable. Valero would likely rely upon the I-Plan Option 3. However, this option does not allow any additional time for the installation of controls on the FCCU. In order to meet the next scheduled turnaround, any engineering design would need to be completed and an application submitted in approximately one year. Given the limited footprint at the Wilmington Refinery, as noted above and previously communicated to the District, an engineering design is a complex task and will take more time. Therefore, we request that the percentage of emission reductions for Phase I of the I-Plan Option 3 be reduced to allow additional time to properly design a pollution control system for the FCCU. 3-3

Again, Valero is committed to working with the District to resolve all remaining RECLAIM transition issues and to obtain the emission reductions necessary in the South Coast Air Basin.

Sincerely,

Mark Phair
Vice President and General Manager

Staff Response to Comment Letter #3:

Response to Comment 3-1:

BARCT analysis for PR 1109.1 has been conducted consistent with the state law. The cost effectiveness analysis which is one of the important steps in conducting BARCT analysis, focuses on the capital costs and the operating and maintenance costs associated with achieving the proposed NOx limits. Costs associated with purchasing RTCs are not considered in the BARCT analysis since those costs are associated with the RECLAIM program and are not a compliance option under PR 1109.1. Facilities that elected to use RTCs in lieu of installing controls during RECLAIM gained the advantage of not having to pay for controls to comply with the RECLAIM shave to achieve the BARCT requirement for those units. However, there was never any guarantee that the rules would never be amended to require command-and-control BARCT. Staff's analysis indicates that the proposed BARCT limits are achievable and cost effective for Valero. The BARCT analysis accounts for existing pollution controls at the facility for each equipment category. Hence, it would be inappropriate for the BARCT analysis to account for emission reductions that occurred at a facility unrelated to PR 1109.1 for a completely different equipment category.

Response to Comment 3-2:

Staff performed a very thorough BARCT analysis consistent with the state law for PR 1109.1. One of the steps in determining BARCT for each class and category is the cost effectiveness analysis. The 2 ppmv BARCT NOx limit for the FCCU category was established based on the cost effectiveness for FCCUs. The cost effectiveness for the FCCUs with an SCR to meet the Table 1 NOx limit of 2 ppmv was greater than $100,000 per ton of NOx reduced. However, the cost effectiveness for FCCUs without an SCR to meet the Table1 NOx limit is $24,000 per ton of NOx reduced. Since an SCR will achieve 90% to 95% NOx reduction, it is technically feasible for the FCCU at Valero to achieve the 2 ppmv limit. FCCUs that have already installed SCR are properly treated as a separate source category from uncontrolled units because they cannot cost-effectively meet the same emissions limit. Establishing the class or category of source is within the discretion of the South Coast AQMD, taking into consideration the factors listed in the BARCT definition. The fact that there are only a few units in each category does not change this principle. PR 1109.1 excludes units that are installing SCR from using the Conditional Limits when it is technically feasible for those units to achieve Table 1 NOx limits. Changing the approach for one FCCU could potentially enable for other units subject to PR 1109.1 to comply only with the Table 2 conditional NOx limits when the pollution controls installed can meet the Table 1 NOx limits. Staff is also concerned that this approach allows an operator to create a "budget" of excess emissions that would result in higher NOx concentration levels from other units within the B-Plan and B-Cap. Staff is opposed to allowing this or any unit that will be installing SCR to use Table 2 conditional limits as this would result in a substantial weakening of PR 1109.1.

Response to Comment 3-3:

I-Plan Option 3 is unique in that it is available to operators that are currently achieving an emission rate of 0.02 lb/MMBtu based on 2021 annual emissions for boilers and process heaters greater than or equal to 40 MMBtu/hour. Based on discussions with the commenter, I-Plan Option 3 was modified to reduce the percent reduction target for phase 1 from 50 to 40%. This will allow the operator to install pollution controls for meeting 2 ppmv level in Table 1 for the FCCU in the second phase of the I-Plan. This refinery is smaller than the other affected facilities with lower emissions per rated capacity of the equipment. With a smaller pool of affected equipment, the facility has less flexibility with implementation timing especially when the FCCU project achieves a majority of the overall facility reduction potential.

Comment Letter #4:

September 14, 2021

Chair Benoit and Members of the Committee
Stationary Source Committee
South Coast Air Quality Management District ("South Coast AQMD")
crodriguez@aqmd.gov

Re: Agenda Item No. 2-Refinery NOx Rule

Dear Chair Benoit and Members of the Stationary Source Committee:

On behalf of the undersigned organizations, we write regarding Proposed Rule 1109.1. We have actively and in good faith participated in the rulemaking process for this rule for years. All the while, our members and supporters have continued to suffer from pollution levels from refineries that exceed what would occur if they had adopted state-of-the-art technology that has been readily available for more than a decade. We are at the point where we need to end the debate and call the question at the Board. Will this Board have the courage to adopt a life-saving regulation that will achieve more emissions reductions than any stationary source rule adopted in the last decade? We hope the answer is yes, but recent analysis conducted by staff make the decision all the more easy. 4-1

The only reason opposition is happening over this rule stems from oil companies' desires to protect their shareholders' interests. The socioeconomic analysis, which is very conservative, shows that this rule will create thousands of jobs a year. At its peak in 2032, this rule will create more than 4,400 jobs.[1] Moreover, the rule will save 370 lives, prevent more

[1] South Coast AQMD, Draft Socioeconomic Report for Draft Socioeconomic Impact Assessment For Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations Proposed Amended Rule 1304 – Exemptions Proposed Amended Rule 2005 – New Source Review for RECLAIM, at p. ES-7, *available at* 1109-1-draft-socioeconomic-impact-assessment-090721-merged.pdf (aqmd.gov).

than 6,200 asthma attacks, and prevent more than 21,000 missed workdays.[2] If passing a rule that saves hundreds of lives, keeps kids in school instead of at home with respiratory problems, and allows our economy to be even more productive is so controversial, then we have to question what this agency is doing.

We recognize that powerful and entrenched interests have spent years delaying and weakening this rule. And, we recognize that these same interests have sought to make it hard for public officials to stand for public health and job creation over the parochial interests of individual oil companies. But, too many lives are on the line, and we need you to have the courage to take this basic step that is so clearly in the public interest. This rule is not perfect, and we would like it to be much stronger. For example, this rule provides a decade to install life-saving pollution controls that should have been installed a decade or more ago. But, the more time we continue to waste in debates, the more people will get sick and die. Let's make 2021 the year the South Coast AQMD passes an important regulation to clean up warehouses and the most significant South Coast refinery pollution measure in a decade. 4-1 (con'td)

We appreciate your consideration of these comments, and we look forward to courageous debate placing the interest of public health in the forefront during the Stationary Source Committee this week.

Sincerely,

Oscar Espino Padron
Byron Chan
Adrian Martinez
Earthjustice

Jane Williams
California Communities Against Toxics

Maya Golden-Krasner
Center for Biological Diversity

Alicia Rivera
Ashley Hernandez
Alison Hahm
Julia May
Communities for a Better Environment

Chris Chavez
Coalition for Clean Air

Taylor Thomas
Jan Victor
Whitney Amaya
East Yard Communities for Environmental Justice

David Pettit
Natural Resources Defense Council

Monica Embrey
Nicole Levin
Sierra Club

cc: Wayne Nastri

[2] *Id.* at p. ES-8.

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Staff Response to Comment Letter #4:

Response to Comment 4-1:

Staff appreciates the support for the proposed rule and reiterates the purpose of the rule is to reduce NOx emissions from refineries by requiring pollution control technologies to be installed on emission sources to improve the air quality in the region. As the commentator highlighted, the Socioeconomic Assessment concluded the proposed project would generate jobs and result in benefits to public health in terms of avoiding premature deaths, asthma attacks, and loss of workdays. With regard to timing, the PR 1109.1 is currently on track for the Governing Board to consider approval of PR 1109.1, and companion rules, at the November 5, 2021 Governing Board meeting.

Comment Letter #5:

Torrance Refining Company

Torrance Refining Company LLC
3700 W. 190th Street
Torrance, CA 90504
www.pbfenergy.com

September 17, 2021

VIA E-MAIL: srees@aqmd.gov

Sarah Rees, Ph.D.
Deputy Executive Officer
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on South Coast Air Quality Management District Staff's Proposed Rules 1109.1, 429.1 and 1304 related to the 75-Day Package released to the Public on Friday, August 20, 2021

Dear Dr. Rees:

Torrance Refining Company LLC ("TORC") is pleased to submit comments to the South Coast Air Quality Management District ("District") in response to staff's Proposed Rules 1109.1, 429.1 and 1304 related to the 75-Day Package released on August 20, 2021 ("75-Day Package"). This letter supplements TORC's previous comment letters submitted to the District on November 20, 2020, December 14, 2020, January 27, 2021, two letters on April 16, 2021, June 21, 2021, and August 4, 2021.

<u>Rule 1109.1 Comments</u>

(d) Emission Limits

(d)(2)(B)(ii) – *"No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable."*

A Permit to Operate could be issued as well. The District needs to clarify in this section that the NOx and CO emission limits need to be met no later than 18 months after either the Permit to Construct or the Permit to Operate is issued, not just the Permit to Construct. 5-1

Additionally, this seems to conflict with Sections (d)(8) and (d)(9). The District needs to clarify that if a refinery completes construction within 18 months consistent with Table 2, then based on the averaging period, the refiner is subject to the NOx and CO limits per Section (d)(8) and (d)(9).

Sarah Rees, Ph D., *Re: South Coast Air Quality Management District's Proposed*
September 17, 2021 *Rule 1109.1 Rulemaking*
Page 2

(f) Interim Emission Limits

Table 5: Interim NOx Emission Rates for Boilers and Process Heaters ≥ 40 MMBtu/hr

The District has included interim limits for "Units that are < 40 MMBtu/hr" in Table 4. Since Table 5 are interim limits for Units ≥ 40 MMBtu/hr, Units that are < 40 MMBtu/hr with CEMS should be removed from the table as they would have to meet two interim limits. 5-2

(g) Compliance Schedule

Table 6 – Compliance Date. No later than 36 months after a South Coast AQMD Permit to Construct is issued. 5-3

The District should clarify that the 36- month period in this Section means the time to construct the emission control equipment, not meet the limit as allowed per (d)(8) and (d)(9). This should be clarified in the Draft Staff Report.

(i) I-Plan, B-Plan, and B-Cap Submittal and Approval Requirement

(i)(5)(C) – *"An owner or operator shall modify an approved I-Plan, B-Plan, or B-Cap if:*

> *(iii) A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that unit in the currently approved I-Plan, B-Plan, or B-Cap;"* 5-4

Since the I-Plan and the B-Plan may also have a lower Alternate BARCT or Conditional NOx Limit than what was approved, the District should remove the word "higher." Further, the District should clarify that this Section applies to both BARCT NOx Limits and Conditional Limits as well.

(j) CEMS Requirements

(j)(3) – *"An owner or operator of a unit with a CEMS that measures CO at [DATE OF ADOPTION] must operate and maintain the CO CEMS pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Table 1, Table 2, or Table 3 CO emissions limits and certify the CEMS within 12 months of [DATE OF ADOPTION] pursuant to the applicable Rules 218.2 and 218.3 requirements."* 5-5

The District should clarify that this section should only apply to CO CEMS that were installed to meet District Rules and Regulations. CO CEMS subject to federal rules should not be required to meet District Rules 218.2 or 218.3 or the averaging period of the rule.

(l) Diagnostic Emission Checks

This section does not include how long to conduct the Diagnostic Emission Checks. The District should clarify in this Section that the duration of the Diagnostic Emissions Checks should be consistent with the BARCT or Conditional Limit averaging periods. 5-6

Sarah Rees, Ph D., *Re: South Coast Air Quality Management District's Proposed*
September 17, 2021 *Rule 1109.1 Rulemaking*
Page 3

(n) Exemptions

(n)(3) – *"Low-Use Process Heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour*

An owner or operator of a process heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour that is fired at less than 15 percent of the rated heat input capacity on an annual basis, shall be exempt from the applicable emission limits in Table 1, Table 2, and an approved B-Plan" 5-7

The District has included low use exemptions for Boiler < 40 MMBtu/hr and Process Heaters ≥ 40 MMBtu/hr. The District should also include in Section (n)(3) Low-Use Boilers that are only used at less than 15 percent of the rated heat input capacity on an annual basis.

Rule 429.1 Comments

(c) Definitions 5-8

The definition of "CATALYST MAINTENANCE" should also include any ancillary equipment to the SCR system such as the NH3 injection system and the induced draft fan.

(d) Requirements

(d)(8) – *"An owner or operator of a unit equipped with a NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery which has a stack or duct that exists prior to [Date of Adoption] that allows for the exhaust gas to bypass the NOx post-combustion control*

equipment and that elects to use a bypass to conduct catalyst maintenance shall:

> *(A) Not use a bypass if the unit is scheduled to operate continuously for less than five years between planned maintenance shutdowns of the unit;*
>
> *(B) Not use a bypass to conduct catalyst maintenance for more than 200 hours in a rolling three-year cycle;* 5-9
>
> *(C) Operate the unit at the minimum safe operating rate of the unit when the NOx post-combustion control equipment is bypassed;*
>
> *(D) Submit documentation from the manufacturer of the minimum safe operating rate for the unit being bypassed to the South Coast AQMD;"*

The term "minimum safe operating rate of the unit" should clearly refer to the Process Unit, not the combustion device. The minimum rate or turndown of a combustion device could be lower than the safe operating rate of the Process Unit and would cause the unit to shut down. The combustion device's operation will be dictated by the operating rate of the Process Unit. Further, the minimum safe operating rate is determined by the Refinery, not a manufacturer. Therefore, documentation should not be required.

Sarah Rees, Ph D., *Re: South Coast Air Quality Management District's Proposed*
September 17, 2021 *Rule 1109.1 Rulemaking*
Page 4

(f) Recordkeeping

(f)(2) – *"An owner or operator of a unit equipped with NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery shall maintain on-site documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment and make this information available to the South Coast AQMD upon request."* 5-10

Refineries' Title V permits include permit conditions for specific temperatures when the injection of NH3 should begin in the SCR system for optimal NOx reduction. Therefore, this requirement should also include … "unless the minimum temperature requirement is in the Refinery's permit."

<u>Rule 1304 Comments</u>

(f) Limited BACT Exemption

(f)(A) – *"The new or modified permit unit is located at a RECLAIM or former RECLAIM facility and is being installed or modified to comply with a South Coast AQMD rule to meet a specified NOx Best Available Retrofit Control Technology (BARCT) emission limit initially established before December 31, 2023;"* 5-11

The Draft Staff report for PAR 1304 indicates that Section (f)(1)(A) limits the BACT exemption to new or modified permit units being installed or modified at RECLAIM or former RECLAIM facilities to comply with a NOx BARCT rule to transition the NOx RECLAIM program to command-and-control regulatory structure. Therefore, it appears that the intent of this exemption is that it not only applies to BARCT emission limits, but Conditional, B-Plan and B-CAP emission limits as well. For avoidance of doubt, particularly in the permitting process, The District should clarify this Section accordingly.

* * *

In closing, as noted above, there remains proposed rule language that requires additional clarification to create rulemaking that is clear, unambiguous, and achieves the desired goal without creating undesirable effects. As noted, TORC will continue to work with District Staff to address these concerns.

Thank you for the opportunity to submit comments on the 75-day Package. We will continue to work diligently with District staff and other stakeholders to address the complex issues associated with this package.

Please note that in submitting this letter, TORC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the PR 1109.1 rulemaking process.

If you have any questions regarding TORC's comments, please call or email me or John Sakers. Our office phone numbers are 310-212-4500 (Steve) and (310) 212-4292 (John).

Sincerely,

Steve Steach
Refinery Manager

cc: **District Staff - via e-mail and overnight delivery**

Wayne Nastri	Executive Officer
Susan Nakamura	Assistant Deputy Executive Officer
Michael Krause	Planning and Rules Manager
Michael Morris	Planning and Rules Manager

cc: **District Refinery Committee Members - via e-mail and overnight delivery**

Hon. Ben Benoit	Governing Board Chair
Hon. Larry McCallon	Governing Board Member and Refinery Committee Chair
Hon. Lisa Bartlett	Governing Board Member and Refinery Committee Member

cc: **District Governing Board Members - via overnight delivery**

Hon. Joe Buscaino	Governing Board Member
Hon. Michael A. Cacciotti	Governing Board Member
Hon. Vanessa Delgado	Governing Board Vice-Chair
Hon. Gideon Kracov	Governing Board Member
Hon. Shelia Kuehl	Governing Board Member
Hon. Veronica Padilla-Campos	Governing Board Member
Hon. V. Manuel Perez	Governing Board Member
Hon. Rex Richardson	Governing Board Member
Hon. Carlos Rodriguez	Governing Board Member
Hon. Janice Rutherford	Governing Board Member

Staff Response to Commenter Letter #5:

Response to Comment 5-1:

Staff clarified the language to include the issuance of a permit to operate. Depending on the project and equipment, a permit to construct and/or permit to operate could be issued; therefore, staff will add both permit types throughout the proposed rule to ensure it is clear and accurate when required timelines are triggered.

Response to Comment 5-2:

Staff concurs that the language in the preliminary draft rule includes two separate interim limits for boilers and heaters <40MMBtu/hour that operate with a certified CEMS. Staff proposes to revise the language to clarify that the facility can elect to comply with either the 40 ppmv interim limit or the 0.03 pound per million Btu emission rate for boilers and process heaters <40MMBtu/hour that operate with a certified CEMS. The rule will include a reporting requirement for the facilities to inform the South Coast AQMD which interim emission limit the boilers and process heaters will be bound to comply with.

Response to Comment 5-3:

Staff modified the proposed rule to clarify that the implementation timeframe to comply with the limits includes construction, commissioning, and initial source test but not the additional time allowed under (f)(8) and (f)(9).

Response to Comment 5-4:

A facility would not be required to modify the I-Plan, B-Plan, or B-Cap if they established a lower NOx limit in the permit than was included in the I-Plan, B-Plan, or B-Cap. A facility may choose to modify the plans but that will not be a requirement under PR 1109.1. A lower NOx limit would result in the even lower emission than in the approved plan; therefore, a modification is not required. A higher NOx limit could require a facility to lower NOx limits for a unit or units in the approved plan; therefore, a modification is required.

Regarding the conditional limits, all NOx limits specified in the B-Plan or B-Cap are alternative NOx limits so by definition conditional limits do not have to be specifically mentioned in subparagraph (d)(5)(C).

Response to Comment 5-5:

Staff initially proposed requiring CO CEMS on all units; however, staff revised the proposed rule to only require units with existing CO CEMS to maintain the CEMS. PR 1109.1 is focused on NOx emission reductions while not increasing CO emissions. The CO CEMS requirement was removed to reduce costs for CO compliance to maximize the rule’s ability to achieve NOx reductions; however, there is little to no additional cost for facilities with an existing CO CEMS to continue to use that CEMS. In addition, the operation of the CO CEMS to demonstrate CO limit compliance will allow the facility to not conduct annual source tests to determine CO emissions. Thus, any CO CEMS already installed on a unit subject to PR 1109.1 should maintain the CEMS to demonstrate compliance with the rule.

Response to Comment 5-6:

Staff concurs with this comment and will clarify the rule to include a 30-minute duration time for the diagnostic check.

Response to Comment 5-7:

PR 1109.1 exempts units with low-use or low-emitting characteristics because they can be very costly to retrofit. Exempting those units reduces the overall cost-effectiveness for the class and category. Staff also evaluates individual units with high cost-effectiveness even if the class and category overall is cost-effective. While not a legal requirement, this assessment is conducted to exclude costly projects that will not achieve significant emission reductions. Staff's evaluation of the boiler category showed the class and category to be very cost effective. However, staff went further and included conditional limits (7.5 ppmv) to address a few units that are achieving very close to the proposed NOx limit of 5 ppmv that would be costly to retrofit. Those units were cost outliers. When evaluating the conditional limits, staff did not identify any other units as cost outliers. Boilers at petroleum refineries are very cost effective to retrofit because they have very high NOx emissions, PR 1109.1 will not include any further exemptions for boilers.

Comment Letter #6:

WSPA

Patty Senecal
Senior Director, Southern California Region

September 17, 2021

Mr. Michael Krause
Manager, Planning and Rules
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Via e-mail at: mkrause@aqmd.gov

Re: SCAQMD Proposed Rule 1109.1, Emissions Of Oxides Of Nitrogen From Petroleum Refineries And Related Operations
WSPA General Comments on Draft Rule Language (August 20, 2021 Revision)

Dear Mr. Krause,

Western States Petroleum Association (WSPA) appreciates the opportunity to participate in the Working Group Meetings (WGMs) for South Coast Air Quality Management District (SCAQMD or District) Proposed Rule 1109.1, Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR1109.1). This proposed rulemaking is part of the District's larger project to transition facilities in the Regional Clean Air Incentives Market (RECLAIM) program for NO_X emissions to a command-and-control structure (i.e., the "RECLAIM Transition Project"). WSPA is a non-profit trade association representing companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas, and other energy supplies in five western states including California. WSPA has been an active participant in air quality planning issues for over 30 years. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the RECLAIM Program administered by the SCAQMD and will be impacted by PR1109.1.

On August 20, 2021, SCAQMD released Preliminary Draft Rule Language for PR1109.1 (Draft Rule).[1] The District has requested written comments on this rule by September 17, 2021. WSPA will be providing written comments on PR429.1 and PR1304, both of which are critical to the PR1109.1 rulemaking package. With this letter, WSPA is providing comments on the PR1109.1 Preliminary Draft Rule Language. In addition, we are attaching a redlined version of the District's August 20 version of PR 1109.1 rule based on the below comments. WSPA understands that SCAQMD is working on revising the Draft Rule, and we may provide comments on the revised language after it has been released.

1. **Dates and deadlines for compliance are presented in numerous sections of the proposed rule. For clarity, all compliance dates should be presented in Section (g), Compliance Schedule. Additionally, all compliance dates for meeting emission limits should be based on the date of issuance of a Permit to Construct.** 6-1

[1] SCAQMD Proposed Rule 1109.1 Preliminary Draft Rule Language, released August 20, 2021. Available at SCAQMD PR1109.1 page.

September 17, 2021
Page 2

Section (g) of the rule provides requirements for the compliance schedule. However, a number of dates and deadlines are presented in other sections of the proposed rule.

For example, Section (d)(2)(B)(ii) states:

> *No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O_2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable.*

All dates for permit application submission, compliance, etc. should be consolidated in Section (g) for clarity and to ensure there are no internal conflicts. Affected sections include, but are not limited to: (d)(2)(B), (d)(3), (d)(4), (d)(8), (d)(9), (e)(1)(A), and (e)(2)(A).

Additionally, dates for compliance with the rule's emissions standards should be based on the date a permit to construct/operate is issued. For example, Section (g)(2)(I) states: 6-1 (cont'd)

> *(I) For an owner or operator with an approved B-Cap, demonstrate compliance with the emissions requirements and all other requirements no later than the compliance date for Phase I in I-Plan Option 4 and no later 54 months from South Coast AQMD Permit Application Submittal Date for all other phases of the selected iPlan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets.*

A facility has no control over whether the District issues a permit within a specified time period. Therefore they should not be held to a compliance date that is dependent on an application submittal date. All compliance requirements that are based on permit issuance should be tied to a time period after permit issuance. We have provided proposed language changes for each of these sections in the attached redlined version of the proposed rule.

2. **In multiple sections the Draft Rule language requires that a facility submit a complete application. The word "complete" has a specific regulatory meaning. Having an application deemed "complete" by the District is outside the control of the facility. This language should be removed from the rule.**

Several sections in the Draft Rule language require the facility submit a "complete" application package. For example (d)(2)(B) states:

> *(B) Before July 1, 2022, submit a complete South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2.*

SCAQMD Rule 210 provides the requirements for applications for a permit required under Rules 201, 203, and 208. It states: 6-2

> *(b) The Executive Officer shall notify the applicant in writing within 30 calendar days of the receipt of an application for a permit, pursuant to Rule 201, as to whether or not the application contains sufficient information to be deemed complete. Upon receipt of any resubmittal or additional information after the application has been deemed incomplete a new 30-day period shall begin during which the Executive Officer shall determine and notify the applicant regarding completeness of the application…*

Because the word "complete" has a specific regulatory meaning, and the onus to deem an application complete lies with the District, the word "complete" should be removed from language requiring a facility to submit an application.

3. **Section (d)(2). Under section (d)(2)(C) the District is proposing that an owner or operator shall meet the Conditional NOx and CO Emission Limits in Table 2 if the unit is listed in Table D-1 or D-2. Owners or operators choosing to comply with a B-Plan or** 6-3

B-Cap will have the flexibility to choose the alternative endpoint for the emission unit, including for units listed in Tables D-1 or D-2.

WSPA recommends the language be updated as follows:

(d) Conditional NOx and CO Emission Limits

(2) An owner or operator of a ~~u~~Unit ~~is eligible~~ may elect to meet the NOx and CO emission limits in Table 2~~,~~ in lieu of the NOx and CO emission limits in Table 1 provided: 6-3 (cont'd)

(C) Notwithstanding subparagraph (d)(2)(A) ~~and (d)(2)(B)~~, ~~an owner or operator shall meet~~ the Conditional NOx and CO Emission Limits in Table 2 apply to a Unit in lieu of the NOx and CO Emission Limits in Table 1 if:

4. **Section (d)(2)(A)(i) could curtail the option to comply with Table 2 limits for any unit issued a permit on or after December 4, 2015 for installation of a post combustion control device for the unit. This creates a potential concern for stranded assets resulting from projects implemented as a result of the 2015 Amendments to Regulation XX (i.e. the RECLAIM shave). WSPA recommends the language be altered to eliminate this condition.**

Under Section (d)(2)(A), the District is proposing:

(A) An owner or operator of a unit is eligible to meet the NOx and CO emission limits in Table 2, in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a post combustion control device for the unit; 6-4

Companies have instigated emission control projects in response to the 2015 RECLAIM amendments. Facilities were not required to meet a specified endpoint for the RECLAIM shave. Therefore, a project may be underway or completed that reduces NOx emissions to below the Table 2 Conditional Limit, but not as low as the Table 1 BARCT Limit. The requirement above results in the potential for stranded asset issues on recently installed NOx control equipment. WSPA recommends the language be updated as follows:

(A) An owner or operator of a ~~u~~Unit ~~is eligible~~ may elect to meet the NOx and CO emission limits in Table 2~~,~~ in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct with an emission limit at or below the Table 1 NOx emission limit on or after December 4, 2015 for the installation of a post combustion control device for the unit;

5. **Sections (d)(3)(A) and (d)(4)(A) would require that operators of Boilers and Process Heaters <40 MMBtu/hr have a SCAQMD permit that includes an enforceable emission limit before January 1, 2023. While a facility can apply for a permit by a certain date, they do not control when the permit is issued by SCAQMD. WSPA understands from PR1109.1 WGM #25 that SCAQMD intends to revise the language in (d)(3) and (d)(4) to include a permit submittal deadline rather than requiring units to have a permit by a certain date. WSPA agrees with this change.** 6-5

WSPA recommends the language be altered as follows:

(A) ~~Before January 1, 2023, have a South Coast AQMD Permit that includes~~ Submit a South Coast AQMD Permit application by no later than January 1, 2023 requesting ~~an enforceable~~ emission limits ~~that does~~ not to exceed 40 ppmv NOx and 400 ppmv

CO, at three percent O_2 correction, as demonstrated pursuant to ~~and limits~~ the averaging times specified in ~~to~~ Table 1 or subdivision (k), whichever is applicable. 6-5 (cont'd)

6. **Section (d)(4). The District has proposed that existing refinery heaters < 40 MMBtu/hr meet an initial BARCT limit of 40 ppmv NO_X pursuant to paragraph (d)(4) and Table 4 (Interim NO_X and CO Emission Limits). While these limits are proposed to go into force shortly after rule adoption, the District has not demonstrated whether the existing heaters in the category can meet this limit without new emission controls.**

   Under Section (d)(4)(A), the District is proposing:

   (4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour An owner or operator of a process heater with a rated heat input capacity less than 40 MMBtu/hour shall:

   (A) Before January 1, 2023, have a South Coast AQMD Permit that includes an enforceable emission limit that does not exceed 40 ppmv NOx and 400 ppmv CO at three percent O2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable; 6-6

   These same NO_X and CO limits are also proposed as Interim Limits in Table 4 of the rule, so facilities would be required to comply with them shortly after rule adoption.

   The District previously acknowledged that some of the existing heaters in the category do not meet this level of emissions. At WGM #14, units in the category were reported to have current NO_X emissions ranging from 5 to 100 ppmv.[2] This was also acknowledged by the District at WGM #25.[3] The District needs to determine how many units are likely to require new emissions controls.

7. **The District has not completed the cost effectiveness analyses required to establish a 40 ppm NO_X BARCT standard for refinery heaters < 40 MMBtu/hr category.**

   As discussed above, there appear to be a number of heaters in the category that currently do not meet the proposed standard of 40 ppmv NO_X (based on a 2-hr average). The District has not provided stakeholders an assessment of the potential compliance costs or cost effectiveness. To the contrary, the District claimed there would be zero compliance cost for heaters < 20 MMBtu/hr to meet a 40 ppmv NO_X level, and negligible costs (i.e., $3,900/tpy) for heaters rated 20-40 MMBtu/hr to meet a 30 ppmv NO_X level.[4] 6-7

   Based on recommendations from the District's third-party expert (i.e., Norton Engineering Consultants, NEC), the District later revised its BARCT proposal for the 20-40 MMBtu/hr heaters category to 40 ppmv NO_X and combined it with the <20 MMBtu/hr category.[5] The District has not presented stakeholders with a revised analysis of compliance costs or cost effectiveness for either the two original categories, or the now combined category. This is necessary to establish BARCT.

[2] SCAQMD PR1109.1 WGM #14 Presentation, August 27, 2020. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm-14-ab617-community.pdf?sfvrsn=22.
[3] SCAQMD PR1109.1 WGM #25, September 15, 2021, slides 17-18. Available at http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1_wgm25_presentation.pdf?sfvrsn=10.
[4] [4] SCAQMD PR1109.1 WGM #14 Presentation, August 27, 2020. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm-14-ab617-community.pdf?sfvrsn=22.
[5] SCAQMD PR1109.1 WGM #16 presentation, Slides 19-22, December 10, 2020, Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm16.pdf?sfvrsn=4

8. The proposed Interim Limits for the <40 MMBtu/hr heater category may need to be revised pursuant the District's "Guiding Principles" for Interim Limits.

For Interim Limits, District's outlined the following "Guiding Principles:" [6]

- "Interim limits would reflect current operating conditions until BARCT emission limits are achieved and ensure enforceable emission limits are in place;
- "Interim limits are not an interim step down to BARCT emission limits;
- "Interim limits will apply to individual units and ensure RACT requirements are being met; and 6-8
- Interim limits will be incorporated in PR1109.1 for units that have compliance dates after January 1, 2024."

In the case of the <40 MMBtu/hr heater category, the District is proposing Interim Limits (Table 4) which are identical to the initial BARCT limits pursuant to Section (d)(4). But as noted above, these may not actually represent "hold the line" levels for some of the heaters in the category. The District needs to consider whether different (i.e., higher) Interim Limits are needed to accomplish the objectives laid out in the Guiding Principles.

9. Sections (d)(3)(C) and (d)(4)(C). The District has proposed that existing refinery boilers and heaters <40 MMBtu/hr meet a more stringent deferred BARCT limit of 5 ppmv and 9 ppmv NOx, respectively. The District has not completed the analyses required to establish either of these limits as a BARCT standard.

Under Section (d)(3)(C), the District is proposing:

(3) Boilers with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a boiler with a rated heat input capacity less than 40 MMBtu/hour shall…

(C) No later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a boiler or replaces burners that represent 50 percent or more of the heat input in a boiler, where the cumulative replacement begins from July 1, 2022, shall: 6-9

(i) Submit a complete South Coast AQMD permit application to impose a 5 ppmv NOx emission limit and a 400 ppmv CO emission limit at three percent O2 correction that limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and

(ii) Meet the emission limits pursuant to clause (d)(3)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

Under Section (d)(4)(C), the District is proposing:

(4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a process heater with a rated heat input capacity less than 40 MMBtu/hour shall…

(C) Effective [TEN YEARS AFTER DATE OF ADOPTION], no later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners on a process heater of replaces burners that represent 50 percent or more of the heat input in a process heater, where the

[6] PR1109.1 WGM #21 presentation, Slide 27, May 27, 2021. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1_wgm21_presentation-mtgversion.pdf?sfvrsn=12

cumulative replacement begins [FIVE YEARS AFTER DATE OF ADOPTION] shall:

(i) Submit a complete South Coast AQMD permit application to inpose 9 ppmv NOx emission limit and a and 400 ppmv CO emission limit at three percent O2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and

(ii) Meet the emission limits pursuant to clause (d)(4)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

The District has not completed the cost-effectiveness analyses required to establish either of these deferred BARCT standards. California Health & Safety Code §40406 defines BARCT as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and *economic impacts* by each class or category of source" (*Emphasis added*).[7]The District has not provided stakeholders an actual assessment of the potential compliance costs or the cost-effectiveness for these units. Instead, it has established requirements which would arbitrarily dictate when equipment will be deemed to have reached an "end-of-useful life," and then claims that facilities would have no additional cost because "(m)ajority of cost will already be incurred by facility upon replacement."[8]

6-9
(cont'd)

Additionally, for process heaters <40 MMBtu/hr, the District has taken the position that it can establish a "technology forcing" BARCT standard based on emerging technologies which it reasonably expects to be available at some future time. Regardless, the District would still be obligated to demonstrate technical feasibility prior to imposing such a BARCT standard.

The District has proposed this emerging technology standard based on burner technology products which the District hopes may be available at some future date. But the District has noted at several PR1109.1 working group meetings that these burner products are still in the research & development (R&D) phase and are not commercially available. The District has pushed the effective date for this 9 ppmv NOx requirement in Section (d)(4)(B) to "ten years after date of adoption," but this is an arbitrary and uncertain date. The District has no way to know whether these products will achieve commercially readiness within 10 years, or ever.

WSPA has previously commented that any such technology forcing standard must be subject to a District-led technology review step before the BARCT standard becomes effective. The stationary sources subject to PR1109.1 are not involved with the R&D or commercialization of the products on which the District's standard would rely, and they have no ability to ensure it happens on an arbitrary District timetable.

In establishing a BARCT standard, the District must follow the Health & Safety Code requirements to demonstrate technical feasibility and cost-effectiveness. And in this case, the District has not met either obligation.

10. Section (e)(2)(B)(ii). The language in Section (e)(2)(B)(ii) would significantly restrict the flexibility for choosing emission limits within the B-Cap option. WSPA recommends that the language in this section be removed from the rule. 6-10

Under Section (e)(2)(B), the District has proposed:

[7] California Health and Safety Code §40406. Available at: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC

[8] SCAQMD, Preliminary Draft Staff Report for Proposed Rule 1109.1, released August 20, 2021, page 4-7 et seq. Available at SCAQMD PR1109.1 page.

(2) An owner or operator of a facility with six or more units that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall…

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and Phase III to meet the respective Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed… 6-10 (cont'd)

(ii) The Conditional NOx and CO limit in Table 2, for any unit that is meeting a Conditional NOx and CO Emission Limit pursuant to subparagraphs (d)(2)(A) or (d)(2)(B).

The purpose of the B-Cap is to allow facilities the flexibility to choose an Alternative BARCT NOx Limit. Therefore, facilities should not be required to meet the Conditional NOx Limit in Table 2. WSPA recommends that the language in Section (e)(2)(B)(ii) be removed from the rule.

11. Section (e)(2)(D). The BARCT endpoints for units should be based on the category of the equipment, irrespective of whether the facility is choosing to comply with the Table 1 and Table 2 standards, as applicable, or to utilize the B-Plan or B-Cap alternative compliance approaches. Thus, units subject to Table 1 emission limits should be represented as Table 1 units, and units subject to Table 2 emission limits should be represented as Table 2 units for the purpose of calculating emission reductions from decommissioning.

WSPA recommends the language in Section (e)(2)(B) be updated as follows: 6-11

(2) An owner or operator of a facility with six or more units that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall:

(D) For any ~~u~~Unit that is permanently decommissioned, represent the decommissioned ~~u~~Unit as Table 1 or Table 2 NOx emissions, as applicable, in the Phase I, Phase II, ~~or~~ and if applicable Phase III Facility BARCT Emission Target in an approved B-Cap, ~~and for the unit that is decommissioned the owner or operator shall~~:

12. Section (e)(2)(F)(iv). The language in Section (e)(2)(F)(iv) would impose additional restrictions for using emission reductions resulting from decommissioning units to meet the Facility BARCT Emission Target. This requirement does not result in additional emission reductions from facilities choosing the B-Cap option. Thus, the language should be removed from the rule.

Under Section (e)(2)(F)(iv), the District is proposing: 6-12

(2) An owner or operator of a facility with six or more units that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall…

(F) Not add a new unit that will be subject to this rule that increases the facility emissions above applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, unless…

(iv) The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of Final Phase Facility BARCT Emission Target in an approved B-Cap.

Facilities operating under an approved B-Cap should be allowed to take credit for all emission reductions from decommissioned units. Therefore, the language in Section (e)(2)(F)(iv) should be removed from the rule. 6-12 (cont'd)

13. Section (f). Boilers and heaters rated at <40 MMBtu/hr operating with NOx CEMS are required to meet Interim Emission Limits listed in both Sections (f)(1) and (f)(2)(A), and therefore are double regulated. WSPA recommends that these units be subject to either the Limits in Table 4 or the Limits in Table 5, but not both. 6-13

14. Section (g). The language in Section (g)(1) addresses compliance schedule for owners or operators of a unit that is required to meet the Table 1 emission limits. Section (g) does not address the compliance schedule for units that will meet the Table 2 Conditional Limits. WSPA recommends that the compliance schedule for units meeting the Conditional Limits be moved from Section (d)(2)(B) to a new Section (g)(2).

WSPA recommends that the requirements currently listed in Section (d)(2)(B) be moved to a new Section (g)(2) to address the compliance schedule for units complying with Table 2 Conditional Limits. 6-14

(g)(2) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emission limits in Table 2 in lieu of the NOx and CO emission limits in Table 1 shall:

(A) Before July 1, 2022, submit a South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2; and

(B) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable.

15. Section (i)(4) provides the criteria for approval of the I-Plan, B-Plan, or B-Cap. As written, the language could be interpreted to allow for SCAQMD disapproval for any reason. WSPA recommends that the language be revised such that the plan will be approved provided it meets the listed criteria. WSPA also recommends that a timeframe for approval or disapproval of a plan be added to the rule language.

Under Section (i)(4), the District is proposing:

(4) The Executive Officer will notify the owner or operator in writing whether the I-Plan, B-Plan, or B-Cap is approved or disapproved based on the following criteria… 6-15

The current rule language could be interpreted to allow for SCAQMD disapproval for any reason, resulting in a source being required to meet the Table 1 and Table 2 limits. The rule language should specify that approval will be granted if the listed criteria are met. Additionally, the rule language should specify a timeline for response from the District for approval or disapproval of a Plan. WSPA recommends the language in Section (i)(4) be updated as follows.

(4) The Executive Officer will notify the owner or operator in writing within 30 days whether the I-Plan, B-Plan, or B-Cap is approved or disapproved. An I-Plan, B-Plan, or B-Cap will be approved provided it meets ~~based on~~ the following criteria…

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16. Section (k) addresses source test requirements. Quarterly source testing is onerous and inconsistent with rules applicable to similar equipment. WSPA recommends that the required source test frequency be once/year.

Section (k) provides source test requirements. Table 7, Source Testing Schedule for Units without Ammonia Emissions in the Exhaust, and Table 8, Source Testing Schedule for Units with Ammonia Emissions in the Exhaust provide the source test schedule. Depending on whether a unit is operated with or without various pollutant CEMS, the rule requires source testing quarterly during the first 12 months of being subject to a Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit (as applicable), and quarterly thereafter. The tables state that source tests may be conducted annually after the first 12 months if four consecutive quarterly source tests demonstrate compliance with emission limits. 6-16

Rule 1146, Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters requires source testing every 3 years for units with a rated heat input capacity ≥10 MMBtu/hr and every 5 years for units with a rated heat input capacity 5 – <10 MMBtu/hr. Rule 1146.1 Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, requires source testing every five years for units with a rated heat input capacity >2 - <5 MMBtu/hr. Rule 1134, Emissions of Oxides of Nitrogen from Stationary Gas Turbines, requires source testing on gas turbines every 1-3 years, depending on annual emissions of the unit.

The quarterly source tests in the Draft Rule language would be onerous and costly. The regulations for similar equipment require source testing every 1 – 5 years depending on equipment type. WSPA recommends that the required source test frequency be reduced to once per year.

17. Section (k)(3) addresses the source test schedule for units with ammonia emissions in the exhaust. PR 1109.1 does not limit ammonia emissions and does not require ammonia CEMS. Therefore, all items related to ammonia, including source test requirements, should be handled during the permitting process. Section (k)(3) should be removed from the rule. 6-17

18. Attachment B, Section B-2. It is understood that the intent of Section (d)(2)(C) and, by reference, Tables D-1 and D-2 is that these units would be Conditional Limit units by rule. To achieve this effect, the wording in Section B-2 should be revised.

WSPA recommends the language in Attachment B, Section B-2 be updated as follows:

(B-2) Final Phase Facility BARCT Emission Target

The Final Phase Facility BARCT Emission Target is the Phase II Facility BARCT Emission Target for an I-Plan option with two phases or the Phase III Facility BARCT Emission Target for an I-Plan option with three phases. The Final Phase Facility BARCT Emission Target is used to establish the Phase II or Phase III BARCT Emission Target for a B-Cap. To establish the Final Phase Facility BARCT Emission Target, the owner or operator must select whether ~~if~~ the basis of the emission target for each ~~u~~Unit will be based on Table 1 or Table 2 NOx concentration limits. The owner or operator shall only select Table 2 NOx concentration limits if the requirements of subparagraphs (d)(2)(A) and (g)(2) for the Conditional NOx Limits are met or if the ~~u~~Unit is identified pursuant to subparagraph (d)(2)(C) ~~in~~ and Attachment D. For all other ~~u~~Units, the owner or operator shall use NOx limits from Table 1 as the basis of the Facility BARCT 6-18

Emission Target. To calculate the Final Phase Facility BARCT Emission Target for B-Cap, the owner or operator shall use NOx concentration limits from ~~of~~ Table 1 for the ~~u~~Units that will be decommissioned. 6-18 (cont'd)

19. Attachment B, requires that the Facility BARCT Emission Target be reduced by 10 percent for a B-Cap program. While WSPA does not agree with the inclusion of this additional environmental benefit, if it remains, the rule should provide the flexibility to meet the benefit by other means.

In Attachment B, Section B-4, the District is proposing:

(B-4) Calculating Phase I, Phase II, or Phase III Facility BARCT Emission Target

The Phase I, Phase II, or Phase III Facility BARCT Emission Targets are the total NOx mass emissions per facility based on the Total Facility NOx Emission Reductions and the Percent Reduction Target of Phase I, Phase II or Phase III of an I-Plan option in Table 6. For a B-Cap, each phase Facility BARCT Emission Targets shall be reduced by 10 percent.

U.S. EPA's Economic Incentive Program (EIP) Guidance[9] indicates that the B-Cap is not an EIP. For example, when describing the types of discretionary EIPs, the EIP Guidance includes statements such as the following:

- An EIP may be an emission trading program, a financial mechanism program, a program such as a clean air investment fund (CAIF) that has features of both trading and financial mechanism programs, or a public information program.[10] 6-19
- The four general types of EIPs are emission trading programs, financial mechanisms, CAIFs, and public information programs.[11]
- Unlike traditional CAA regulatory mechanisms, emission trading involves more than one party.[12]

Since the B-Cap does not involve trading, and clearly does not qualify as any of the other types of EIPs covered by the EIP Guidance, the B-Cap should not be subject to review under the EIP Guidance.

While the US EPA EIP gudaince does generally require an additional environmental benefit to be included for certain applicable programs,the guidance "recognizes that the type of demonstration appropriate will depend on the goals and characteristics of the EIP [being] implemented."[13] Other options for providing environmental benefit, in addition to the 10% additional emissions reduction, are as follows:

- Showing greater or more rapid emission reductions due to trading (e.g., early reductions)
- Reducing emission reductions generated by program participants by at least 10 percent
- Showing other environmental management improvements

[9] Improving Air Quality with Economic Incentive Programs, US EPA, January 2001. Available at: https://www.epa.gov/sites/default/files/2015-07/documents/eipfin.pdf. Accessed: September 2021.
[10] *Id*. at p. 15.
[11] *Id.* at p. 18
[12] *Id.* at p. 78.
[13] *Id.* at p. 56

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- Improved administrative mechanisms (for example, your EIP achieves emissions reductions from sources not readily controllable through traditional regulation)
- Reduced administrative burdens on regulatory agencies that lead to increased environmental benefits through other regulatory programs
- Improved emissions inventories that enhance and lend increased certainty to State planning efforts 6-19 (cont'd)
- The adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches.
- For multi-source cap and trade program or a single source cap and trade program, includes a declining cap

If the requirement remains, the language should be updated to reflect the flexibility to meet the environmental benefit requirement by other means, as allowed in the EPA EIP Guidance Document.

20. **Additional minor revisions and language clarifications are provided in the attached redline version of the Preliminary Draft Rule.** 6-20

WSPA appreciates the opportunity to provide these comments related to PR1109.1. We look forward to continued discussion of this important rulemaking. If you have any questions, please contact me at (310) 808-2144 or via e-mail at psenecal@wspa.org.

Sincerely,

Patty Senecal

Attachment

Cc: Wayne Nastri, SCAQMD
Susan Nakamura, SCAQMD

Proposed Draft Rule

(Adopted TBD)
Revision Date 8-20-21

PROPOSED RULE 1109.1. EMISSIONS OF OXIDES OF NITROGEN FROM PETROLEUM REFINERIES AND RELATED OPERATIONS

(a) Purpose

The purpose of this rule is to reduce emissions of oxides of nitrogen (NOx), while not increasing carbon monoxide (CO) emissions, from units at petroleum refineries and facilities with related operations to petroleum refineries.

(b) Applicability

The provisions of this rule shall apply to an owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries.

(c) Definitions

(1) ALTERNATIVE BARCT NOx LIMIT ~~FOR PHASE I, PHASE II, OR PHASE III~~ means a ~~the unit~~Unit specific NOx concentration limit that is selected by the owner or operator to achieve the Phase I, Phase II, or if applicable Phase III, Facility BARCT Emission Target in the aggregate in a~~the~~ B-Plan or B-Cap, where the NOx concentration limit ~~will~~ includes the corresponding percent O_2 correction and ~~determined based on~~ the averaging time specified in Table 1 or subdivision (k), whichever is applicable.

(2) ASPHALT PLANT means a ~~f~~Facility that processes crude oil into asphalt.

(3) BASELINE FACILITY EMISSIONS means the sum of all the Baseline Unit Emissions at a Facility as calculated according to Attachment B of this rule.

(4) BASELINE UNIT EMISSIONS means ~~a Unit's~~ emissions from a Unit as reported in the 2017 NOx Annual Emissions Report, or another representative year, as approved by the Executive Officer.

(5) BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator to select Alternative BARCT NOx ~~concentration l~~Limits for all Units subject to this rule that are equivalent, in the aggregate, to the NOx concentration limits specified in Table 1 and Table 2.

(6) BARCT EQUIVALENT MASS CAP PLAN (B-CAP) means a compliance plan that establishes a Facility mass emission cap ~~for all units subject to this rul~~that, in the aggregate, is~~are~~ equivalent to or less than the Final Phase Facility BARCT Emission Target.

(7) BIOFUEL PLANT means a Facility that produces fuel by processing feedstocks including vegetable oil, animal fats, and tallow.

(8) BOILER means any Unit that is fired with gaseous fuel and used to produce steam. For the purpose of this rule, ~~b~~Boiler does not include CO ~~b~~Boilers.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(9) CO BOILER means a ~~boiler~~ Unit that is fired with gaseous fuel with an integral waste heat recovery system used to oxidize CO-rich waste gases generated by the FCCU.

(10) CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) is as defined by Rule 218 – Continuous Emission Monitoring.

(11) DUCT BURNER means a device in the heat recovery steam generator of a Gas Turbine that combusts fuel and adds heat energy to the ~~g~~Gas ~~t~~Turbine exhaust.

(12) FACILITIES WITH RELATED OPERATIONS TO PETROLEUM REFINERIES includes Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, ~~p~~Petroleum ~~c~~Coke ~~c~~Calcining ~~f~~Facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants.

(13) FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

(14) FACILITY means, for the purpose of this rule, any ~~u~~Unit or group of ~~u~~Units which are located on one or more contiguous properties, in actual physical contact or separated solely by a public roadway or other public right-of- way, and operate under one South Coast AQMD Facility ID or Facilities ~~w~~With ~~t~~The Same Ownership.

(15) FINAL DETERMINATION NOTIFICATION means the notification issued by the Executive Officer to a RECLAIM ~~f~~Facility designating that the ~~f~~Facility is no longer in the NOx RECLAIM program.

(16) FINAL PHASE FACILITY BARCT EMISSION TARGET means the total mass emissions remaining per Facility calculated based on the applicable ~~Table 1~~ emission limits in Table 1 or Table 2 ~~conditional emission limits~~ and the Baseline Emissions.

Commented [A1]: "Baseline Emissions" is not defined.

(17) FLARE means, for the purpose of this rule, a combustion device that oxidizes combustible gases or vapors from tank farms or liquid unloading, where the combustible gases or vapors being destroyed are routed directly into the burner without energy recovery, and that is not subject to Rule 1118 – Control of Emissions from Refinery Flares or Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing.

(18) FLUIDIZED CATALYTIC CRACKING UNIT (FCCU) means a Unit in which petroleum intermediate feedstock is charged and fractured into smaller molecules in the presence of a catalyst; or reacts with a contact material to improve feedstock quality for additional processing; and the catalyst or contact material is regenerated by burning off coke and other deposits. The FCCU includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat including a CO ~~b~~Boiler.

(19) FORMER RECLAIM FACILITY means a Facility, or any of its successors, that was

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

in the NOx Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a Final Determination Notification, and is no longer in the NOx RECLAIM program.

(20) FUNCTIONALLY SIMILAR means, for the purpose of this rule, a Unit that will perform the same purpose as a Unit that was decommissioned in an approved B-Cap.

(21) GAS TURBINE means an internal-combustion engine in which the expanding combustion gases drive a turbine which then drives a generator to produce electricity. Gas Turbines can be equipped with a cogeneration gas turbine that recovers heat from the Gas Turbine exhaust and can include a Duct Burner.

(22) HEAT INPUT means the heat of combustion released by burning a fuel source, using the Higher Heating Value of the fuel. This does not include the enthalpy of incoming combustion air.

(23) HIGHER HEATING VALUE (HHV) means the total heat liberated per mass of fuel combusted expressed as British thermal units (Btu) per pound or cubic feet when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to their standard states at standard conditions.

(24) HYDROGEN PRODUCTION PLANT means a Facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes which primarily supplies hydrogen for ~~p~~Petroleum ~~r~~Refineries and Facilities with Related Operations to Petroleum Refineries.

(25) IMPLEMENTATION COMPLIANCE PLAN (I-PLAN) means an implementation plan for Facilities with six or more Units that includes an ~~alternative~~ implementation schedule and emission reduction targets.

(26) I-PLAN PERCENT REDUCTION TARGET means the percent reduction target ~~specified~~ for each phase of an I-Plan as specified in Table 6.

(27) NATURAL GAS means a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

(28) NEW UNIT means, for the purpose of this rule, any Unit that is subject to this rule ~~meets the applicability of subdivision (b)~~ where the South Coast AQMD Permit to Construct is issued on or after [*DATE OF ADOPTION*].

(29) OXIDES OF NITROGEN (NOx) EMISSIONS means the sum of nitric oxide and nitrogen dioxide emitted in the flue gas, calculated, and expressed as nitrogen dioxide.

(30) PARTS PER MILLION BY VOLUME (ppmv) means, for the purpose of this rule, milligram of pollutant per liter of dry combustion exhaust gas at standard conditions.

(31) PETROLEUM COKE CALCINER means a Unit used to drive off contaminants from

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

green petroleum coke by bringing the coke into contact with heated gas for the purpose of thermal processing. The Petroleum Coke Calciner includes, but is not limited to, a kiln, which is a refractory lined cylindrical device that rotates on its own axis, and a pyroscrubber, which combusts large carbon particles in a stream of waste gas.

(32) PETROLEUM COKE CALCINING FACILITY means a ~~Unit within a~~ Petroleum Refinery, or ~~as~~ a separate Facility, that operates a ~~p~~Petroleum ~~c~~Coke ~~c~~Calciner.

(33) PETROLEUM REFINERY means a Facility identified by the North American Industry Classification System Code 324110, Petroleum Refineries.

(34) ~~PHASE I, PHASE III, OR PHASE III~~ BARCT B-CAP ANNUAL EMISSIONS means the total Facility NOx mass emissions remaining based on ~~per Facility that incorporates BARCT~~ Alternative BARCT NOx Limits for Phase I, Phase II, and if applicable Phase III, decommissioned ~~unit~~Units, and other emission reduction strategies to meet the respective Phase I, Phase II, or if applicable Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

(35) ~~PHASE I, PHASE II, OR PHASE III~~ BARCT EQUIVALENT MASS EMISSIONS means the Facility total NOx mass emissions remaining based on ~~per Facility that incorporates respective BARCT~~ Alternative BARCT NOx Limits for Phase I, Phase II, and if applicable Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or if applicable Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

(36) ~~PHASE I, PHASE II, OR PHASE III~~ FACILITY BARCT EMISSION TARGET means the total Facility NOx mass emissions ~~per Facility~~ that must be achieved in an approved B-Plan or B-Cap ~~that are~~ based on the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan ~~option in Table 6~~ and are calculated pursuant to Attachment B of this rule.

(37) PROCESS HEATER means any Unit fired with gaseous and/or liquid fuels which transfers heat from combusted gases to water or process streams.

(38) RATED HEAT INPUT CAPACITY means the maximum heat input capacity, which is the total heat of combustion released by burning a fuel source, as specified by the South Coast AQMD permit.

(39) REPRESENTATIVE NOx CONCENTRATION means the most representative NOx emissions in the exhaust of the Unit ~~as approved by the Executive Officer and~~ measured by a certified CEMS if the Unit operates with a certified CEMS or the most recent approved source test for ~~u~~Units not operating a certified CEMS. The

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Representative NOx Concentration for ~~u~~Units that do not have CEMS or source test emission data will be based on the South Coast AQMD Annual Emission Report default emission factor for th~~at~~ose Units.

(40) RULE 1109.1 EMISSION LIMITS mean the NOx and CO emission limits and corresponding percent O_2 correction listed in paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 4, Table 5, an approved B-Plan, or an approved B-Cap.

(41) STANDARD CONDITIONS for a Former RECLAIM Facility is as defined by Rule 102 – Definition of Terms.

(42) STEAM METHANE REFORMER (SMR) HEATER means any Unit that is fired with gaseous fuels and transfers heat from the combusted fuel to process tubes that contain catalyst, which converts light hydrocarbons combined with steam to hydrogen.

(43) SULFURIC ACID FURNACE means a Unit fueled with gaseous fuels and/or hydrogen sulfide gas used to convert elemental sulfur and/or decompose spent sulfuric acid, into sulfur dioxide (SO_2) gas.

(44) SULFURIC ACID PLANT means a Unit within a Petroleum Refinery, or ~~as~~ a separate Facility, engaged in the production of commercial grades of sulfuric acid, or regeneration of spent sulfuric acid into commercial grades of sulfuric acid.

(45) SULFUR RECOVERY PLANT means a Unit within a Petroleum Refinery, or ~~as~~ a separate Facility, that recovers elemental sulfur or sulfur compounds from sour or acid gases and/or sour water generated by Petroleum Refineries.

(46) SULFUR RECOVERY UNITS/TAIL GAS (SRU/TG) INCINERATORS means the thermal or catalytic oxidizer where the residual hydrogen sulfide in the gas exiting the ~~s~~Sulfur ~~r~~Recovery ~~p~~Plant (tail gas) is oxidized to SO_2 before being emitted to the atmosphere.

(47) UNIT means, for the purpose of this rule, any ~~b~~Boilers, ~~f~~Flares, FCCUs, ~~g~~Gas ~~t~~Turbines, ~~p~~Petroleum ~~c~~Coke ~~c~~Calciners, ~~p~~Process ~~h~~Heaters, SMR ~~heaters~~Heaters, ~~s~~Sulfuric ~~a~~Acid ~~f~~Furnaces, SRU/TG ~~incinerators~~Incinerators, or ~~v~~Vapor ~~i~~Incinerators requiring a South Coast AQMD permit and not required to comply with a ~~another~~ NOx emission limit in another South Coast AQMD Regulation XI rule.

(48) UNIT REDUCTION means the potential NOx emission reduction for a Unit if the Unit's NOx emissions were reduced from the Representative NOx Concentration to the applicable NOx concentration limit in Table 1 based on the Baseline Emissions calculated pursuant to Attachment B of this rule.

Commented [A2]: "Baseline Emissions" is not defined.

(49) UNITS WITH COMBINED STACKS means two or more Units where the flue gas from the~~se~~ Units are combined in one or more common stack(s).

(50) VAPOR INCINERATOR means a thermal oxidizer, afterburner, or other device for

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

burning and destroying air toxics, volatile organic compounds, or other combustible vapors in gas or aerosol form in gas streams.

(d) Emission Limits

(1) Except as otherwise allowed under this rule, on and after the applicable compliance dates established pursuant to subdivision (g), ~~A~~an owner or operator shall not operate a ~~u~~Unit that results in the discharge of NOx and CO at concentrations in excess of ~~exceeds~~ the applicable ~~NOx and CO~~ emission limits in Table 1, at the percent O_2 correction specified in Table 1, and the averaging time specified in Table 1 or subdivision (k), whichever is applicable. ~~pursuant to the compliance schedule insubdivision (g)~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 1: NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to paragraph (d)(3)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to paragraph (d)(4)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

[1] Averaging times apply to ~~u~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Conditional NOx and CO Emission Limits

(A) An owner or operator of a ~~u~~Unit may elect ~~is eligible~~ to meet the NOx and CO emission limits in Table 2~~,~~ in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct with an emission limit at or below the applicable Table 1 NOx emission limit on or after December 4, 2015 for the installation of a post combustion control device for the ~~u~~Unit;

(ii) For a ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour and less than or equal to 110 MMBtu/hour ~~or less~~, the Unit Reduction calculated pursuant to Attachment B of this rule is less than 10 tons per year ~~based the applicable Table 1 NOx emission limit~~;

(iii) For ~~b~~Boilers or ~~p~~Process ~~h~~Heaters with a Rated Heat Input Capacity greater than 110 MMBtu/hour, the Unit Reduction calculated pursuant to Attachment B of this rule is less than 20 tons per year ~~based on the applicable Table 1 NOx emission limit~~;

(iv) The South Coast AQMD Permit to Construct or South Coast AQMD Permit to Operate for the ~~u~~Unit does not have a condition that limits the NOx concentration to a level at or below the applicable Table 1 NOx emission limit;

(v) The Representative NOx Concentration of the ~~u~~Unit is not at or below the applicable Table 1 NOx emission limit; and

(vi) The ~~u~~Unit is not identified as being decommissioned in an approved B-Plan for reductions in an I-Plan~~or approved B- Cap~~ pursuant to subparagraph (e)(1)(D).

~~(B) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emission limits in Table 2 in lieu of the NOx and CO emission limits in Table 1 shall:~~

~~(i) Before July 1, 2022, submit a complete South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2; and~~

~~(ii) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O_2 correction and the averaging time specified~~

~~(C)~~(B) ~~in Table 2 or subdivision (k), whichever is applicable~~Notwithstanding

Commented [A3]: Relates to Schedule. Moved to section (g).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

subparagraphs (d)(2)(A) ~~and (d)(2)(B), an owner or operator shall meet~~the Conditional NOx and CO Emission Limits in Table 2 apply to a Unit in lieu of the NOx and CO Emission Limits in Table 1 if:

(i) The owner or operator of the Unit is submitting a B-Plan ~~or a B-Cap~~, and the~~ir~~ ~~u~~Unit is listed in Table D-1; or

(ii) The owner or operator of the Unit is submitting a B-Cap and has selected I-Plan Option 4, and the~~ir~~ ~~u~~Unit is listed in Table D-2.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 2: CONDITIONAL NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters 40 – 10 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	24-hour

[1] Averaging times apply to ~~u~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

(3) Boilers with Rated Heat Input Capacity Less Than 40 MMBtu/hour

An owner or operator of a ~~b~~Boiler with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour shall:

(A) ~~Before January 1, 2023, have~~Submit a South Coast AQMD Permit application by no later than January 1, 2023 requesting ~~that includes an enforceable~~ emission limits ~~that does~~ not to exceed 40 ppmv NOx and 400 ppmv CO, at three percent O_2 correction, as demonstrated pursuant to ~~and limits~~ the averaging times specified in ~~to~~ Table 1 or subdivision (k)~~,~~ whichever is applicable.

(B) On and after ~~January 1, 2023~~the date of Permit to Construct/Operate issuance, not operate a ~~b~~Boiler that exceeds 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction as demonstrated pursuant to the averaging times specified in Table 1 or subdivision (k), whichever is applicable; and

(C) No later than six months after an owner or operator cumulatively replaces

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

either 50 percent or more of the burners in a ~~b~~Boiler or replaces burners that represent 50 percent or more of the ~~heat~~ Heat ~~i~~Input in a ~~b~~Boiler, where the cumulative replacement begins on~~from~~ July 1, 2022, shall:

(i) Submit a ~~complete~~ South Coast AQMD permit application requesting emission limits not to exceed ~~to impose a~~ 5 ppmv NOx ~~emission limit~~ and ~~a~~ 400 ppmv CO, ~~emission limit~~ at three percent O_2 correction, as demonstrated pursuant to ~~that limits~~ the averaging times specified in ~~to~~ Table 1 or subdivision (k)~~,~~ whichever is applicable; and

(ii) Meet the emission limits specified in ~~pursuant to~~ clause (d)(3)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

Commented [A4]: Move to Section (g)

(4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour and without a certified CEMS shall:

(A) Submit ~~Before January 1, 2023, have~~ a South Coast AQMD Permit application by no later than January 1, 2023 requesting ~~that includes an enforceable~~ emission limits not to exceed ~~that does not exceed~~ 40 ppmv NOx and 400 ppmv CO, at three percent O_2 correction, as demonstrated pursuant to ~~and limits~~ the averaging times ~~to~~ specified in Table 1 or subdivision (k)~~,~~ whichever is applicable;

(B) On and after ~~January 1, 2023~~the date of Permit to Construct/Operate issuance, not operate a ~~p~~Process ~~h~~Heater that exceeds 40 ppmv NOx and 400 ppmv CO, at three percent O_2 correction as demonstrated pursuant to the averaging times specified in Table 1 or subdivision (k)~~,~~ whichever is applicable; and

(C) Effective [*TEN YEARS AFTER DATE OF ADOPTION*], no later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a ~~p~~Process ~~h~~Heater or replaces burners that represent 50 percent or more of the ~~h~~Heat ~~i~~Input in a ~~p~~Process ~~h~~Heater, where the cumulative replacement begins on~~from~~ [*FIVE YEARS AFTER DATE OF ADOPTION*]~~, shall~~:

(i) Submit a ~~complete~~ South Coast AQMD permit application requesting ~~to impose a~~9 ppmv NOx emission limit and a 400 ppmv CO emission limit at three percent O_2 correction and limits the averaging times to those specified in Table 1 or subdivision (k), whichever is applicable; and

(ii) Meet the emission limits specified in ~~pursuant to~~ clause

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(d)(4)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

Commented [A5]: Move to Section (g)

(5) Gas Turbines

Notwithstanding the NOx emission limits in Table 1, an owner or operator shall not operate a ~~g~~Gas ~~t~~Turbine that exceeds 5 ppmv NOx corrected to 15 percent O_2 correction based on a 24-hour rolling average during natural gas curtailment periods, where there is a shortage in the supply of pipeline natural gas due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas, provided:

(A) A daily ~~g~~Gas ~~t~~Turbine operating record is maintained that includes the actual start and stop time, total hours of operation, and type (liquid or gas) and quantity of fuel used; and

(B) This information is available to South Coast AQMD staff upon request for at least five years ~~from the date of entry~~.

(6) An owner or operator of ~~u~~Units with combined stacks shall be subject to the most stringent applicable Table 1 or Table 2 NOx and CO emission limits at the applicable percent O_2 correction based on the averaging times specified in Table 1 or subdivision (k), whichever is applicable.

(7) An owner or operator of a ~~u~~Unit with a CO emission limit in a South Coast AQMD Permit to Operate that was established before [DATE OF ADOPTION], shall meet the CO emission limit in the Emission and Requirements section of the South Coast AQMD Permit to Operate in lieu of the CO emission limit specified in Table 1, ~~or~~ Table 2, or Table 4.

(8) An owner or operator of a ~~u~~Unit subject to ~~with~~ an averaging time less than a 365-day rolling average in Table 1 or Table 2 that operates a CEMS shall be required to demonstrate compliance with the applicable Rule 1109.1 Emission Limits~~NOx emission limits in Table 1, Table 2, an approved B-Plan, or an approved B-Cap~~ six months after~~,~~ either the date the South Coast AQMD Permit to Operate is issued, 36 months after the South Coast AQMD Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

Commented [A6]: Move to Section (g)

(9) An owner or operator of a ~~u~~Unit subject to a 365-day rolling average in Table 1 or Table 2 shall demonstrate compliance with the applicable Rule 1109.1 Emission Limits beginning 14 months after either the date the South Coast AQMD Permit to Operate is issued, 36 months after the South Coast AQMD Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

Commented [A7]: Move to Section (g)

(e) B-Plan and B-Cap Requirements

(1) An owner or operator of a ~~f~~Facility with six or more ~~u~~Units that elects to meet the NOx emission limits in an approved B-Plan in lieu of meeting the Table 1 or Table

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

2 NOx emission limits shall:

(A) Before July 1, 2022, submit an application for a B-Plan that includes all ~~u~~Units subject to this rule, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx emission limits specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

Commented [A8]: Move to Section (g)

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, for each Unit to meet the respective Phase I, Phase II, and if applicable Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed the applicable conditional NOx emission limit in Table 2 for any Unit that is meeting a conditional NOx emission limit pursuant to subparagraphs (d)(2)(A) and (g)(2)~~:~~;

(i) ~~The Conditional NOx and CO limit in Table 2, for any unit that is meeting a Conditional NOx and CO Emission Limit pursuant to subparagraphs (d)(2)(A) and (d)(2)(B).~~

(C) ~~Comply with a condition in the SCAQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, for each uUnit in the approved B-Plan based on the schedule established in the approved I-Plan; and~~

~~(D) Not include emission reductions for any unit that is permanently decommissioned; and~~

~~(E)~~(D) Not operate a ~~unit~~ Unit in an approved B-Plan that exceeds the Alternative BARCT NOx Limit and applicable~~,~~ CO emission limit, based on the applicable averaging time in Table 1 or ~~the~~ subdivision (k), whichever is applicable, ~~in an approved B-Plan,~~ based on the implementation schedule in an~~the~~ approved I-Plan.

Commented [A9]: Section (C) and (D) are redundant. Delete Section (C)

(2) An owner or operator of a ~~f~~Facility with six or more ~~u~~Units that elects to meet the NOx ~~and CO~~ emission limits in an approved B-Cap in lieu of the NOx emission limits in ~~meeting~~ Table 1 or ~~and~~ Table 2 ~~NOx concentration limits~~ shall:

(A) Before July 1, 2022, submit a B-Cap and an I-Plan that include~~s~~ all ~~u~~Units subject to this rule, with the exception of any ~~b~~Boiler or ~~p~~Process Heater with a Rated Heat Input Capacity of less than 40 MMBtu/hour that will meet the NOx emission limit s specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last ~~C~~compliance ~~D~~date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

Commented [A10]: Move to Section (g)

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, for each Unit to meet the respective Phase I, Phase II, and if applicable ~~or~~ Phase III BARCT Equivalent Mass Emissions where

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the Alternative BARCT NOx Limit shall not exceed~~;~~:

(i) The applicable Maximum Alternative BARCT NOx Limit ~~for the applicable unit,~~ specified in Table 3; and

(ii) The Conditional NOx ~~and CO~~ emission limit in Table 2, for any ~~u~~Unit that is meeting a Conditional NOx ~~and CO~~ ~~E~~emission ~~L~~limit pursuant to subparagraphs (d)(2)(A) and~~or~~ (~~d~~g)(2)~~(B)~~.

(C) Comply with a condition in the South Coast AQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III for each ~~unit~~ Unit in the approved B-Cap based on the schedule established in the approved I-Plan;

(D) For any ~~u~~Unit that is permanently decommissioned, represent the decommissioned ~~u~~Unit as Table 1 or Table 2 NOx emissions, as applicable, in the Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target in an approved B-Cap, and ~~for the unit that is decommissioned the owner or operator shall~~:

(i) Surrender the South Coast AQMD Permit to Operate for the decommissioned Unit no later than the compliance date for Phase I in I-Plan Option 4 and no later than the permit submittal date for all other phases in an approved I-Plan;

(ii) Disconnect and blind the fuel line(s) for the decommissioned Unit on or before the date the Permit to Operate is surrendered pursuant to clause (e)(2)(D)(i); and

(iii) Not sell the ~~unit~~ decommissioned Unit ~~for operation~~ to another entity for operation within the South Coast Air Basin;

(E) Not operate any ~~unit~~ Unit unless the NOx emissions for all ~~units~~ Units in the approved B-Cap are in aggregate at or below the applicable Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target, based on the schedule in the approved I-Plan; and

(F) Not add a new ~~u~~Unit that will be subject to this rule that increases the ~~f~~Facility emissions above applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, unless:

(i) All ~~u~~Units in the approved B-Cap meet the BARCT Equivalent Mass Emissions;

(ii) The new ~~u~~Unit is not ~~f~~Functionally ~~s~~Similar to any ~~u~~Unit that was decommissioned in the approved B-Cap; and

(iii) The new ~~u~~Unit will not increase overall ~~f~~Facility throughput.~~; and~~

~~(iv) The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of Final~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~Phase Facility BARCT Emission Target in an approved B-Cap.~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 3: MAXIMUM ALTERNATIVE BARCT NOX LIMITS FOR A B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-~~day~~hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-~~day~~hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-~~day~~hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SRU/TG Incinerators	100 ppmv	3	24-~~day~~hour
Vapor Incinerators	40 ppmv	3	24-~~day~~hour

[1] Averaging times apply to ~~u~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

(f) Interim Emission Limits

~~(1)~~ An owner or operator of a Former RECLAIM ~~f~~Facility that elects to comply with the emission limits in Table 1, Table 2, or an approved B-Plan shall not operate a ~~u~~Unit that exceeds the applicable interim NOx and CO emission limits in Table 4, based on the measured O_2 correction in Table 4, and the averaging time in Table 4 or

~~(2)~~(1) subdivision (k)~~,~~ whichever is applicable, until that ~~u~~Unit is required to meet another Rule 1109.1 Emission Limit pursuant to the compliance schedule in paragraph (g)(1) or an approved I-Plan.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 4: INTERIM NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour and Boilers and Process Heaters <40 MMBtu/hr operating a certified CEMS	Pursuant to paragraph (f)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciners	85	2,000	3	365-day
SMR Heaters	20[2]	400	3	365-day
	60[3]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	105	400	3	365-day

[1] Averaging times are applicable to ~~u~~Units with a CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

[2] SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [*DATE OF ADOPTION*].

[3] SMR Heaters not equipped with post-combustion air pollution control equipment as of [*DATE OF ADOPTION*].

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Interim NOx emission limits for Boilers and Process Heaters ≥40 MMBtu/hour and <40 MMBtu operating a certified CEMS

An owner or operator of a Former RECLAIM Facility that elects to comply with the emission limits in Table 1, Table 2, or an approved B-Plan, shall:

(A) Not exceed the applicable interim NOx emission ~~rate~~ limit in Table 5, calculated pursuant to Attachment A Section (A-2) of this rule, for all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour ~~and boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate with a NOx CEMS~~.

TABLE 5: INTERIM NOX EMISSION RATES FOR BOILERS AND PROCESS HEATERS ≥40 MMBTU/HOUR and <40 MMBtu/hr operating a certified CEMS

Units	An Owner or Operator that Elects to Comply with an Approved:	Facility NOx Emission Rate (pounds/million Btu)	Rolling Averaging Time
Boilers and Process Heaters: ≥40 MMBtu/Hour and <40 MMBtu/hour |Operating a Certified	B-Plan using I-Plan Option 3	0.02	365-day
	B-Plan	0.03	365-day

(B) Demonstrate compliance with the applicable interim NOx emission ~~rate~~ limit in Table 5 until all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters subject to paragraph (f)(2) meet the NOx concentration limits in Table 1, Table 2, or an approved B-Plan.

(3) An owner or operator of a Former RECLAIM Facility that elects to comply with an approved B-Cap shall not operate any ~~u~~Unit included in the approved B-Cap unless the NOx emissions for all ~~u~~Units in the B-Cap are in aggregate at or below the Baseline Facility Emissions.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(g) Compliance Schedule

(1) An owner or operator of a ~~u~~Unit that elects ~~is required~~ to meet the NOx and CO emission~~concentration~~ limits specified in Table 1 shall:

(A) Before July 1, 2023, submit a ~~complete~~ South Coast AQMD permit application requesting ~~to establish a~~ permit conditions that limit~~s~~ ~~the~~ NOx and CO emissions to the applicable concentrations in Table 1, ~~concentration~~ based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable, unless the owner or operator has a South Coast AQMD Permit to Construct or a South Coast AQMD Permit to Operate with ~~the~~ a NOx concentration limit at or below the applicable Table 1 NOx limit with the percent O_2 correction and ~~, based on~~ the averaging time specified in Table 1; and

(B) Not operate a ~~u~~Unit~~,~~ that exceeds the applicable NOx and CO emission limits in Table 1, based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable:

(i) ~~No l~~Later than 36 months after a South Coast AQMD Permit to Construct is issued; or

(ii) ~~No l~~Later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A).

(2) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emissions limits in Table 2 in lieu of the NOx and CO emissions limits in Table 1 shall:

(A) Before July 1, 2022, submit a South Coast AQMD permit application requesting permit conditions that limit NOx and CO emissions to the applicable concentrations in Table 2; and

(B) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO limits in Table 2, at the percent O_2 correction in Table 2, and averaging time specified in Table 2 or subdivision (k) whichever is applicable.

~~(2)~~(3) I-Plan Requirements

An owner or operator of a Facility with six or more ~~u~~Units that elects to meet the NOx and CO emission limits in Table 1 or Table 2 using an alternative compliance schedule to paragraph (g)(1) or that elects to comply with an approved B-Plan or B-Cap shall:

(A) Before July 1, 2022, submit an I-Plan pursuant to paragraph (i)(1) that includes all ~~u~~Units subject to Table 1 or Table 2 NOx emission limits for review and approval pursuant to paragraph (i)(4), with the exception of

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(g) Compliance Schedule

(1) An owner or operator of a ~~u~~Unit that elects ~~is required~~ to meet the NOx and CO emission~~concentration~~ limits specified in Table 1 shall:

(A) Before July 1, 2023, submit a ~~complete~~ South Coast AQMD permit application requesting ~~to establish a~~ permit conditions that limit~~s~~ ~~the~~ NOx and CO emissions to the applicable concentrations in Table 1, ~~concentration~~ based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable, unless the owner or operator has a South Coast AQMD Permit to Construct or a South Coast AQMD Permit to Operate with ~~the~~ a NOx concentration limit at or below the applicable Table 1 NOx limit with the percent O_2 correction and ~~, based on~~ the averaging time specified in Table 1; and

(B) Not operate a ~~u~~Unit~~,~~ that exceeds the applicable NOx and CO emission limits in Table 1, based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable:

(i) ~~No l~~Later than 36 months after a South Coast AQMD Permit to Construct is issued; or

(ii) ~~No l~~Later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A).

(2) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emissions limits in Table 2 in lieu of the NOx and CO emissions limits in Table 1 shall:

(A) Before July 1, 2022, submit a South Coast AQMD permit application requesting permit conditions that limit NOx and CO emissions to the applicable concentrations in Table 2; and

(B) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO limits in Table 2, at the percent O_2 correction in Table 2, and averaging time specified in Table 2 or subdivision (k) whichever is applicable.

~~(2)~~(3) I-Plan Requirements

An owner or operator of a Facility with six or more ~~u~~Units that elects to meet the NOx and CO emission limits in Table 1 or Table 2 using an alternative compliance schedule to paragraph (g)(1) or that elects to comply with an approved B-Plan or B-Cap shall:

(A) Before July 1, 2022, submit an I-Plan pursuant to paragraph (i)(1) that includes all ~~u~~Units subject to Table 1 or Table 2 NOx emission limits for review and approval pursuant to paragraph (i)(4), with the exception of

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

any ~~b~~Boiler or ~~p~~Process ~~h~~Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour that will meet the NOx emission limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

(B) Calculate the Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Targets~~,~~ pursuant to Attachment B of this rule;

~~For a B-Cap, the Phase I, Phase II, and Phase III Facility BARCT Emission Targets shall incorporate a reduction of 10 percent, pursuant to Attachment B of this rule;~~

(C) For a B-Plan, calculate the Phase I, Phase II, and if applicable~~or~~ Phase III BARCT Equivalent Mass Emissions, pursuant to Attachment B of this rule;

(D) For a B-Plan, demonstrate that Phase I, Phase II, and if applicable~~or~~ Phase III, BARCT Equivalent Mass Emissions~~,~~ are equal to or less than the respective Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target;

(E) For a B-Cap, calculate the Phase I, Phase II, and if applicable~~or~~ Phase III BARCT B-Cap Annual Emissions, pursuant to Attachment B of this rule;

(F) For a B-Cap, demonstrate that Phase I, Phase II, and if applicable~~or~~ Phase III BARCT B-Cap Annual Emissions, are equal to or less than the respective Phase I, Phase II, ~~or~~ and if applicable Phase III Facility BARCT Emission Target;

(G) Based on the schedule in the approved I-Plan, implement emission reduction projects to comply with the emission limits in Table 1 or Table 2 or an approved B-Plan or approved B-Cap, to achieve the Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target; and

(H) For an owner or operator with an approved B-Cap, demonstrate compliance with the emissions requirements and all other requirements no later than the compliance dates listed in Table 6 for the chosen I-Plan ~~for Phase I in I-Plan Option 4 and no later 54 months from South Coast AQMD Permit Application Submittal Date for all other phases of the selected I- Plan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets~~.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 6: I-PLAN PERCENT REDUCTION TARGETS AND SCHEDULE[1]

		Phase I	Phase II	Phase III
I-Plan Option 1 for B-Plan Only	Percent Reduction Targets	70	100	N/A
	Permit Application Submittal Date	July 1, 2023	January 1, 2027	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 2 for B-Plan Only	Percent Reduction Targets	60	80	100
	Permit Application Submittal Date	July 1, 2023	January 1, 2025	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		
I-Plan Option 3 for B-Plan or B-Cap and as allowed pursuant to paragraph (g)(3)	Percent Reduction Targets	50	100	N/A
	Permit Application Submittal Date	January 1, 2025	January 1, 2029	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 4 for B-Cap Only	Percent Reduction Targets	50 to 60 (Still in development)	80	100
	Permit Application Submittal Date	N/A	January 1, 2025	January 1, 2028
	Compliance Date	January 1, 2024	No later than 36 months after a South Coast AQMD Permit to Construct is issued	
I-Plan Option 5 for B-Cap Only	Percent Reduction Targets	50	70	100
	Permit Application Submittal Date	July 1, 2022	July 1, 2024	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		

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~~(3)~~(4) I-Plan Option 3 is only available to an owner or operator of a ~~f~~Facility achieving a NOx emission rate of less than 0.02 pound per million BTU of ~~h~~Heat ~~i~~Input, based on annual emissions for the applicable ~~u~~Units as reported in the 2021 Annual Emissions Report and calculated pursuant to Attachment A, for all the ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour based on the maximum rated capacity by [*DATE OF ADOPTION*]; for ~~u~~Units firing at less than the maximum rated capacity, mass emissions shall be less than or equal to the quantity that would occur at maximum rated capacity.

~~(4)~~(5) An owner or operator of a ~~u~~Unit complying with Table 2 conditional emission limits that replaces existing NOx control equipment shall:

(A) Within six months of replacing the existing NOx control equipment, be subject to the applicable Table 1 emission limit;

(B) Apply for a South Coast AQMD permit condition to limit the NOx and CO concentration to the applicable Table 1 emission limit, at the corresponding percent O_2 correction, and averaging times in Table 1 or subdivision (k)~~,~~ whichever is applicable. Replacement of existing NOx control equipment will be determined as:

(i) Existing post-combustion air pollution control equipment for an FCCU, ~~g~~Gas ~~t~~Turbine fueled with natural gas, ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour, or SMR Heater is replaced such that the fixed capital cost of the new components for the post- combustion air pollution control equipment exceeds 50 percent of the fixed capital cost that would be required to construct and install a comparable new ~~u~~Unit; or

(ii) 50 percent or more of the burners in a ~~v~~Vapor ~~i~~Incinerator, or 50 percent or more of the ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity of the burners in a ~~v~~Vapor ~~i~~Incinerator, are cumulatively replaced after [*DATE OF ADOPTION*].

~~(5)~~(6) An owner or operator of ~~u~~Unit complying with clauses (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A) that fails to submit a ~~complete~~ South Coast AQMD permit application by the date specified in clauses (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A), shall meet the applicable Rule 1109.1 Emission Limits no later than 36 months after the South Coast AQMD permit application submittal date pursuant to clauses (d)(2)(B)(i), (d)(3)(C)(i), or (d)(4)(C)(i), or subparagraphs (g)(1)(A) or (g)(5)(A).

~~(6)~~(7) An owner or operator of a ~~u~~Unit exempt from the Table 1 NOx and CO emission

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limits pursuant to paragraphs (n)(2), (n)(3), (n)(6), (n)(7), (n)(8) or (n)(9) that exceeds the applicable exemptions limitations shall:

(A) Within six months of the exceedance, submit a ~~complete~~ South Coast AQMD permit application to comply with the corresponding Table 1 emission limits; and

(B) Meet the emission limits specified on Table 1 no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(h) Time Extensions

(1) An owner or operator of a ~~u~~Unit may request one 12--month extension for each ~~u~~Unit from the compliance date in paragraph (g)(1) or the Compliance Date in Table 6 provided:

(A) The South Coast AQMD permit application for the ~~u~~Unit was submitted on or before the date specified in paragraph (g)(1) or the approved I-Plan; and

(B) There are specific circumstances outside of the control of the owner or operator that necessitate an extension of time.

(2) An owner or operator of a ~~u~~Unit with an approved I-Plan may request a time extension from the Compliance Date in Table 6 for a ~~u~~Unit provided:

(A) The South Coast AQMD permit application for the ~~u~~Unit was submitted on or before the date specified in the approved I-Plan;

(B) The month and year for the ~~u~~Unit's scheduled turnaround and the month and year for the ~~u~~Unit's subsequent turnaround is submitted in writing at the time of South Coast AQMD permit application submittal; and

(C) One or more of the following occurred:

(i) The South Coast AQMD Permit to Construct for the ~~unit~~ Unit was issued after the scheduled turnaround date or the South Coast AQMD Permit to Construct for the ~~u~~Unit was issued more than 24 months after the South Coast AQMD permit application was submitted, and either:

(ii) The subsequent scheduled turnaround for the ~~u~~Unit will not occur until 12 months after the Compliance Date in the approved I-Plan; or

(iii) The subsequent scheduled turnaround for the ~~u~~Unit will occur more than 48 months after the South Coast AQMD Permit to Construct was issued.

(3) An owner or operator that requests a time extension pursuant to paragraphs (h)(1) or (h)(2) shall submit the request in writing to the Executive Officer no later than 90 days prior to the Compliance Date in paragraph (g)(1) or the approved I-Plan for the ~~u~~Unit. The time extension request shall include:

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(A) The phase and ~~u~~Unit needing a time extension;

(B) The date the South Coast AQMD permit application was submitted;

(C) The additional time needed to complete the emission reduction project;

(D) Specify if the time extension request is for paragraph (h)(1) or (h)(2);

(E) For time extension requests for paragraph (h)(2), provide the month and year of the scheduled turnaround, and the subsequent turnaround, if applicable, for the ~~u~~Unit; and

(F) The reason(s) a time extension is requested.

(4) The Executive Officer will review the request for the time extension and act on the request within 60 days of receipt provided an owner or operator:

(A) Meets the requirements of paragraph (h)(1) or (h)(2), as applicable;

(B) Submitted the written request within the timeframe and includes the applicable information specified in paragraphs (h)(1) and (h)(2); and

(C) For a time extension request pursuant to paragraphs (h)(1) and (h)(2), the owner or operator shall at a minimum:

(i) For delays due to missed milestones, provide information on schedules and/or construction plans documenting the key milestones and which key milestone(s) were delayed with an explanation actions the operator took to ensure milestones were met and why the delay necessitates additional time;

(ii) For delays related to other agency approvals, provide information to substantiate that the submittal of information to the agency was timely, and the date requested for ~~when~~ application ~~was the~~ approval ~~was requested, and documentation from the agency of reason for the delay~~;

(iii) For delays related to the delivery of parts or equipment, provide purchase orders, invoices, and communications from vendors that demonstrate that equipment was ordered in a timely fashion and delays are outside of the control of the operator; and

(iv) For delays related to contract workers, source testers, installers, or other services, provide an explanation of the service, when the service was requested, the response time, and information to substantiate why the delay necessitates additional time.

(D) For a time extension request allowed under paragraphs (h)(2), the owner or operator shall provide documentation to substantiate that one of the provisions under subparagraph (h)(2)(C) have been met.

(5) If the Executive Officer requests additional information to substantiate the time extension request, the owner or operator shall provide that information within the timeframe specified by the Executive Officer.

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(6) If the Executive Officer notifies the owner or operator of approval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within timeframe in the approval, and the approval represents an amendment to the I-Plan.

(7) If the Executive Officer notifies the owner or operator of a disapproval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within 60 calendar days after receiving notification of disapproval of the time extension request or pursuant to the compliance schedule in paragraph (g)(1) or the schedule in an approved I-Plan.

(i) I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

(1) I-Plan Submittal Requirements

An owner or operator that elects to implement an I-Plan pursuant to paragraph (g)(2) to meet the Alternative BARCT NOx Limits in an approved B-Plan or approved B-Cap shall submit an I-Plan to the Executive Officer for review and approval that:

(A) Identifies each ~~u~~Unit subject to th~~ise~~ rule by device identification number with a description of each ~~u~~Unit, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

(B) ~~For facilities to use the time extension pursuant to paragraph (h)(2), i~~Identifies the anticipated start and end date (month and year) of the turnaround schedule for each ~~unit~~Unit;

(C) Specifies either I-Plan Option 1 (for a B-Plan only), I-Plan Option 2 (for a B-Plan only) ~~2~~, I-Plan Option 3 (for a B-Plan or B-Cap), I-–Plan Option 4 (for a B-Cap only), or I-Plan Option 5 (for a B-Cap only) in Table 6;

(D) Calculates the Phase I, Phase II, ~~or~~ and if applicable Phase III, Facility BARCT Emission Target, pursuant to Attachment B of this rule;

(E) For a B-Plan, identifies each ~~u~~Unit that meets the requirements in ~~under~~subparagraph (d)(2)(A) to qualify for use of a conditional NOx emission limit in Table 2 and verifies the owner or operator submitted a ~~complete~~ South Coast AQMD permit application pursuant to clause (~~d~~g)(2)~~(B)(i)~~;

(F) For the selected I-Plan option specified pursuant to subparagraph (i)(1)(B), calculates the Phase I, Phase II, ~~or~~ and if applicable Phase III, Facility BARCT Emission Target~~,~~ pursuant to Attachment B of this rule; and

(G) Identifies each ~~unit~~Unit by device identification number with a description of each ~~unit~~Unit, that cumulatively meets Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) B-Plan Submittal Requirements

An owner or operator that elects to meet Alternative BARCT NOx Limits in an approved B-Plan pursuant to paragraph (e)(1), shall submit a B-Plan to the Executive Officer for review that:

(A) Identifies for each ~~unit~~Unit subject to th~~e~~is rule by device identification number with a description of each ~~unit~~Unit, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

(B) Specifies the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, of the approved I-Plan;

(C) Calculates the Phase I, Phase II, ~~or~~ and if applicable Phase III, BARCT Equivalent Mass Emissions using the Alternative BARCT NOx Limits identified in subparagraph (g)(2)(B), as calculated pursuant to Attachment B of this rule; and

(D) Demonstrates that Phase I, Phase II, and if applicable ~~or~~ Phase III, BARCT Equivalent Mass Emissions are less than the respective Phase I, Phase II, and if applicable ~~or~~ Phase III Facility BARCT Emission Target.

(3) B-Cap Submittal Requirements

An owner or operator that elects to meet the Alternative BARCT NOx Limits in an approved B-Cap pursuant to paragraph (e)(2), shall submit a B-Cap to the Executive Officer for review that:

(A) Identifies each ~~unit~~Unit subject to th~~e~~is rule by the device identification number with a description of the ~~unit~~Unit, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, and:

(B) Specifies the Alternative BARCT NOx Limit that is at or below Maximum Alternative BARCT NOx Limit in Table 3;

(C) Identifies any ~~unit~~Unit that will be decommissioned for each phase of the approved I-Plan;

(D) Identifies any ~~unit~~Unit that will have a reduction in throughput for each phase of the approved I-Plan;

(E) Calculates the Phase I, Phase II, and if applicable~~or~~ Phase III, BARCT Equivalent Mass Emissions using the emission reduction strategies identified in subparagraph (g)(3)(B),~~;~~ as calculated pursuant to Attachment B of this rule; and

(F) Demonstrates that Phase I, Phase II, and if applicable ~~or~~ Phase III, BARCT

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

B-Cap Annual Emissions, are less than the respective Phase I, Phase II, and if applicable ~~or~~ Phase III Facility BARCT Emission Target~~ that incorporates a 10 percent reduction pursuant to subparagraph (g)(2)(C);~~.

(4) I-Plan, B-Plan, and B-Cap Review and Approval Process

(A) The Executive Officer will notify the owner or operator in writing whether the I-Plan, B-Plan, or B-Cap is approved or disapproved. An I-Plan, B-Plan, or B-Cap will be approved provided it meets ~~based on~~ the following criteria:

(i) The I-Plan contains information required in paragraph (i)(1), the B-Plan contains information required in paragraph (i)(2), and the B-Cap contains information required in paragraph (i)(3);

(ii) The owner or operator demonstrates that the requirements of subparagraphs (d)(2)(A) and (~~d~~g)(2)~~(B)~~ have been met for any ~~unit~~Unit that is meeting a Table 2 conditional NOx emission limit~~,~~ in lieu of a Table 1 NOx emission limit, and is not listed in Table D-1 or Table D-2;

(iii) For a B-Plan, the Phase I, Phase II, and if applicable~~or~~ Phase III, Equivalent BARCT Emissions are less than or equal to the respective Phase I, Phase II, and if applicable~~or~~ Phase III, Facility BARCT Emission Target as required in subparagraph (g)(2)(B);

(iv) For a B-Cap, the Phase I, Phase II, ~~or~~ and if applicable Phase III, BARCT B-Cap Annual Emissions are less than or equal to the respective Phase I, Phase II, and if applicable ~~or~~ Phase III, Facility BARCT Emission Target~~ that incorporates a 10 percent reductions pursuant to subparagraph (g)(2)(C)~~;

(v) For a B-Cap, the NOx concentration limit for any ~~unit~~Unit does not exceed the applicable Maximum Alternative BARCT NOx Limits in Table 3.

(B) Within 30 days of receiving written notification from Executive Officer that the I-Plan, B-Plan, or B-Cap is disapproved, the owner or operator shall correct any deficiencies and re-submit the I-Plan, B-Plan, or B-Cap.

(C) Upon receiving written notification from the Executive Officer that the I-Plan, B-Plan, or B-Cap re-submitted pursuant to subparagraph (i)(4)(B) is disapproved, the owner or operator shall comply with the compliance schedule pursuant to paragraph (g)(1).

(5) Modifications to an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(A) An owner or operator that seeks approval to modify an approved I-Plan, an approved B-Plan, or an approved B-Cap shall submit a request in writing to the Executive Officer to modify an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap.

(B) The modification request submitted pursuant to subparagraph (i)(5)(A) shall include all the plan submittal requirements pursuant to paragraph (i)(1) for an approved I-Plan, paragraph (i)(2) for a modification of an approved B-Plan, or paragraph (i)(3) for a modification of an approved B-Plan;

(C) An owner or operator shall modify an approved I-Plan, B-Plan, or B-Cap if:

(i) A ~~unit~~Unit identified as qualifying for the NOx emissions limits in ~~meeting~~ Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (~~d~~g)(2)~~(B)~~;

(ii) A ~~unit~~Unit in an approved B-Cap or B-Plan, identified as qualifying for the NOx emission limits in ~~meeting~~ Table 2 for purposes of establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is decommissioned;

(iii) A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit selected for that ~~unit~~Unit in the currently approved I-Plan, B-Plan, or B-Cap;

(iv) Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase; or

(v) The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed.

(D) Review and approval of any modifications to an I-Plan, B-Plan, or B-Cap shall be conducted in accordance with the review and approval process pursuant to paragraph (i)(4).

(6) Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap
The Executive Officer will make the proposed I-Plan, B-Plan, or B-Cap or proposed modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval.

(7) Plan Fees
The review and approval of an I-Plan, B-Plan, and B-Cap, or review and approval of a modification of an approved I-Plan, B-Plan, and B-Cap shall be subject to applicable plan fees as specified in Rule 306 – Plan Fees.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(j) CEMS Requirements

(1) An owner or operator of a Former RECLAIM Facility with a ~~unit~~Unit with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity of greater than or equal to 40 MMBtu/hour shall install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements to demonstrate compliance with NOx emission limits at the corresponding percent O_2 correction and averaging times.

(2) An owner or operator of a Former RECLAIM Facility with a ~~s~~Sulfuric ~~a~~Acid ~~f~~Furnace subject to the emission limits in Table 1, Table 4, an approved B-Plan or an approved B-Cap shall:

(i) Install, certify, operate, and maintain a CEMS to measure NOx pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Rule 1109.1 Emissions Limits; and

(ii) Within 12 months from [*DATE OF ADOPTION*] shall install, certify, operate, and maintain a CEMS that complies with ~~the~~ Rules 218.2 and 218.3 requirements to measure O_2 and demonstrate compliance with the Rule 1109.1 Emission Limits at the corresponding percent O_2 correction.

(3) An owner or operator of a Former RECLAIM Facility with a ~~unit~~Unit with a CEMS that measures CO at [*DATE OF ADOPTION*] must operate and maintain the CO CEMS pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Table 1, Table 2, or Table 3 CO emissions limits and certify the CEMS within 12 months of [*DATE OF ADOPTION*] pursuant to the applicable Rules 218.2 and 218.3 requirements.

(4) An owner or operator of a Former RECLAIM Facility with ~~for~~ a ~~unit~~Unit with a CEMS shall exclude invalid CEMS data pursuant to Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications.

(5) Missing Data Procedures for a Facility Complying with a B-Cap

An owner or operator of a ~~unit~~Unit with an approved B-Cap with a non-operational CEMS that is not collecting data, shall:

(A) Calculate missing data using the average of the recorded emissions for the hour immediately before the missing data period and the hour immediately after the missing data period, if the missing data period is less than or equal to 8 continuous hours; or

(B) Calculate missing data using the maximum hourly emissions recorded for the previous 30 days, commencing on the day immediately prior to the day the missing data occurred, if the missing data period is more than 8 continuous hours.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(k) Source Test Requirements

(1) An owner or operator of a ~~unit~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) shall be required to conduct a source test, with a duration of at least 15 minutes but no longer than two hours, to demonstrate compliance with Rule 1109.1 Emission Limits pursuant to the source test schedule in either Table 7 or Table 8.

(2) Source Test Schedule for Units without Ammonia Emissions in the Exhaust An owner or operator of a ~~u~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) and does not vent to post-combustion air pollution control equipment with ammonia injection, shall demonstrate compliance with the applicable Rule 1109.1 Emission Limits by conducting source tests according to the schedule in Table 7.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 7: SOURCE TESTING SCHEDULE FOR UNITS WITHOUT AMMONIA EMISSIONS IN THE EXHAUST

Combustion Equipment	Source Test Schedule
Vapor Incinerators less than 40MMBtu/hr, Flares	• Conduct source test simultaneously for NOx and CO within 36 months from previous source test and every 36 months thereafter
All Other Units	
Units Operating without NOx or CO CEMS	• Conduct source test simultaneously for NOx and CO within 12 months of being subject to Rule 1109.1 Emission Limit and ~~quarterly~~ annually thereafter • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO emission limits prior to resuming annual source tests~~
Units operating with NOx CEMS and without CO CEMS	• Conduct source test for CO within 12 months from previous source test and every 12 months thereafter
Units operating without NOx CEMS and with CO CEMS	• Conduct source test for NOx during the first 12 months of being subject to Rule 1109.1 Emission Limit and ~~quarterly~~ annually thereafter • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx emissions limits prior to resuming annual source tests~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(3) ~~Source Test Schedule for Units with Ammonia Emissions in the Exhaust~~
~~An owner or operator of a unit with post-combustion air pollution control equipment that requires ammonia injection shall demonstrate compliance with the applicable Rule 1109.1 Emission Limit and ammonia South Coast AQMD permit limit by conducting a source test according to the schedule in Table 8.~~

~~**TABLE 8: SOURCE TESTING SCHEDULE FOR UNITS WITH AMMONIA EMISSIONS IN THE EXHAUST**~~

~~Combustion Equipment~~	~~Source Test Schedule~~
~~Units operating without NOx, CO, or ammonia CEMS~~	• ~~Conduct source test simultaneously for NOx, CO, and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO, NOx, and ammonia emission limit~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx, CO, and ammonia emissions limits prior to resuming annual source Tests~~
~~Units operating with NOx CEMS and without CO and ammonia CEMS~~	• ~~Conduct source test for CO and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO and ammonia emission limit~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the CO and ammonia emissions limits prior to resuming annual source Tests~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~Combustion Equipment~~	~~Source Test Schedule~~
~~Units operating with NOx and CO CEMS and without ammonia CEMS~~	• ~~Conduct source test for ammonia quarterly during the first 12 months of being subject to an ammonia South Coast AQMD permit limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to an ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests~~
~~Units operating with NOx and ammonia CEMS and without CO CEMS~~	• ~~Conduct source test for CO within 12 months from previous source test and every 12 months thereafter~~
~~Units operating with ammonia CEMS and without NOx or CO CEMS~~	• ~~Conduct source tests to determine compliance with NOx and CO emission limits pursuant to Table 7~~

(4) An owner or operator that elects to install and operate a CEMS to demonstrate compliance with the applicable Rule 1109.1 Emission Limits or ammonia South Coast AQMD permit limit at the corresponding percent O_2 correction shall meet the CEMS requirements under subdivision (j).

(5) An owner or operator of with a ~~u~~Unit subject to a Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit, that is not required to install and operate a CEMS pursuant to subdivision (i) and has not conducted a source test within the schedule in Table 7 or Table 8, shall conduct a source test within:

(A) Six months from being subject to the Rule 1109.1 Emission Limit for ~~unit~~Units with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 20 MMBtu/hour.

(B) 12 months from being subject to the Rule 1109.1 Emission Limit for ~~unit~~Units with a R~~r~~ated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 20 MMBtu/hour.

(6) An owner or operator of a new or modified unitUnit shall conduct the initial source tests within six months from commencing operation.

(7) An owner or operator of a ~~unit~~Unit required to conduct a source test pursuant to

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

subdivision (k) shall:

(A) For ~~unit~~Units that receive a South Coast AQMD Permit to Construct to comply with a Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of at least 2 hours, for approval within 60 days after the Permit to Construct was issued unless otherwise approved by the Executive Officer;

(B) For ~~unit~~Units that receive a South Coast AQMD permit condition that limits NOx or CO to a Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of at least 2 hours, for approval within 60 days after being subject to a Rule 1109.1 Emission limit, unless otherwise approved by the Executive Officer, and

(C) Conduct the source test within 90 days after a written approval of the source test protocol by the Executive Officer is distributed.

(8) At least one week prior to conducting a source test, an owner or operator of a ~~unit~~Unit shall notify the Executive Officer by calling 1-800-CUT-SMOG of the intent to conduct source testing and shall provide:

(A) Facility name and identification number;

(B) Device identification number; and

(C) Date when source test will be conducted.

(9) Unless requested by the Executive Officer, after the approval of the initial source test protocol pursuant to paragraph (k)(7), an owner or operator is not required to resubmit a source test protocol for approval pursuant to paragraph (k)(7) if:

(A) The method of operation of the ~~unit~~Unit has not been altered in a manner that requires a South Coast AQMD permit application submittal;

(B) Rule or South Coast AQMD permit emission limits have not become more stringent since the previous source test;

(C) There have been no changes in the source test method that is referenced in the approved source test protocol; and

(D) The approved source test protocol is representative of the operation and configuration of the ~~unit~~Unit.

(10) An owner or operator of a ~~unit~~Unit shall conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program:

(A) Using a South Coast AQMD approved source test protocol;

(B) Using at least one of the following test methods:

(i) South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or

(ii) South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);

(iii) South Coast AQMD Source Test Method 207.1 for Determination of Ammonia Emissions from Stationary Sources; or

(iv) Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

(C) During operation other than startup and shutdown; and

(D) In as-found operating condition.

(11) An owner or operator of a ~~unit~~Unit shall submit all source test reports, including the source test results and a description of the ~~unit~~Unit tested, to the Executive Officer within 60 days of completion of the source test.

(12) Emissions determined to exceed any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall constitute a violation of the rule.

(13) An owner or operator of a ~~unit~~Unit that exceeds any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall inform the Executive Officer within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known.

(l) Diagnostic Emission Checks

(1) An owner or operator of a ~~unit~~Unit required to perform a source test every 36 months pursuant to subdivision (k) shall:

(A) Perform diagnostic emissions checks of NOx, CO, and O_2 emissions, with a portable NOx, CO, and O_2 analyzer that is calibrated, maintained and operated in accordance with manufacturers specifications and recommendations of the South Coast AQMD Combustion Gas Periodic Monitoring Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Combustion Sources Subject to Rules 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, 1146 – Emissions of Oxides of Nitrogen From Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, and 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters.

(B) Conduct the diagnostic emission checks by a person who has completed an appropriate training program approved by South Coast AQMD in the operation of portable analyzers and has received a certification issued by the South Coast AQMD.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(C) Conduct the diagnostic test every 365 days or every 8760 operating hours, whichever occurs earlier.

(2) A diagnostic emissions check that finds the emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall not constitute a violation of this rule if an owner or operator corrects the problem and demonstrates compliance with another diagnostic emissions check within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known, or shut down the ~~unit~~Unit by the end of an operating cycle, whichever is sooner. Any diagnostic emission check conducted by South Coast AQMD staff that finds emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall be a violation.

(m) Monitoring, Recordkeeping, and Reporting Requirements

(1) Operating Log

An owner or operator of a ~~unit~~Unit shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Time and duration of startup and shutdown events;

(B) Total hours of operation;

(C) Quantity of fuel; and

(D) Cumulative hours of operation to date for the calendar year.

(2) An owner or operator of a ~~facility~~Facility that elects to meet the NOx emission limits in an approved B-Cap pursuant to paragraph (e)(2) shall:

(A) Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for those ~~unit~~Units without CEMS;

(B) Maintain daily records of mass emissions, in pounds (lbs) per day, from all ~~unit~~Units included in an approved B-Cap including:

(i) Emissions during start-ups, shutdowns, and maintenance;

(ii) CEMS data identified as invalid and justification;

(iii) Data substituted for missing data pursuant to paragraph (j)(5);

(C) Demonstrate compliance with the Facility BARCT Emission Target in the B-Cap on a daily basis from 365-day rolling average;

(3) An owner or operator subject to the interim emission rate pursuant to paragraph (f)(2) shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Actual daily mass emissions, in lbs., for all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour;

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(B) Combined maximum ~~r~~Rated ~~h~~Heat ~~i~~Input for all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour; and

(C) Calculated interim NOx emission rate pursuant to Attachment A Section (A-2) of this rule.

(4) An owner or operator of a ~~unit~~Unit shall keep and maintain the following records on-site for five years, except that all data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours, and shall make them available to the Executive Officer upon request:

(A) CEMS data;

(B) Source tests reports;

(C) Diagnostic emission checks; and

(D) Written logs of startups, shutdowns, and breakdowns, all maintenance, service and tuning records, and any other information required by this rule.

(5) An owner or operator of a ~~b~~Boiler or ~~p~~Process ~~h~~Heater that is exempt from the applicable Table 1 emission limits pursuant to paragraphs (n)(5) and (n)(6), or an owner or operator of a flare that is exempt from the applicable Table 1 emission limits pursuant to subparagraph (n)(8)(A) shall:

(A) Within 90 days of [*DATE OF ADOPTION*], install and operate a non-resettable totalizing time meter or a fuel meter unless a metering system is currently installed and the fuel meter is approved in writing by the Executive Officer.

(B) Within 90 days of [*DATE OF ADOPTION*], each non-resettable totalizing time meter or a fuel meter required under subparagraph (m)(4)(A) that requires dependable electric power to operate shall be equipped with a permanent supply of electric power that cannot be unplugged, switched off, or reset except by the main power supply circuit for the building and associated equipment or the safety shut-off switch.

(C) Ensure that the continuous electric power to the non-resettable totalizing time meter or fuel meter required under subparagraph (m)(4)(A) may only be shut off for maintenance or safety.

(D) Within 90 days of [*DATE OF ADOPTION*], ensure that each non-resettable totalizing time meter or fuel meter is calibrated and recalibrate the meter annually, thereafter, based on the manufacturer's recommended procedures. If the non-resettable totalizing time or fuel meter was calibrated within one year prior to [*DATE OF ADOPTION*], the next calibration shall be conducted within one year of anniversary date of the prior calibration.

(E) Monitor and maintain hours of operation records as follows:

(i) For the hours per year validation, using a calibrated non-resettable

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totalizing time meter or equivalent method approved in writing by the Executive Officer; or

(ii) For the annual throughput limit equivalent to hours per year validation, using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer.

(6) An owner or operator of a ~~v~~Vapor ~~i~~Incinerator that is exempt from the applicable Table 1 NOx emission limits pursuant to paragraph (n)(9) shall record:

(A) The annual throughput using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer; and

(B) Emissions using a source test pursuant to subdivision (k) or by using a default emission factor approved in writing by the Executive Officer.

(7) An owner or operator of a ~~unit~~Unit subject to the compliance schedule in subparagraphs (d)(3)(B), (d)(4)(B), and (g)(3)(B) shall maintain records of burner replacement, including number of burners and date of installation.

(8) An owner or operator of a ~~u~~Unit subject to the compliance schedule in subparagraph (g)(3)(A) shall maintain records of the date the existing post-combustion control equipment was installed or replaced.

(n) Exemptions

(1) Boilers or Process Heater with a Rated Heat Input Capacity 2 MMBtu/hour or less The provisions of this rule shall not apply to an owner or operator of a ~~b~~Boiler or ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity 2 MMBtu/hour or less that ~~are~~ is fired with liquid and/or gaseous fuel and used exclusively for space or water heating and is~~are~~ subject to Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters.

(2) Low-Use Boilers with a Rated Heat Capacity of less than 40 MMBtu/hour An owner or operator of a ~~b~~Boiler with a ~~r~~Rated ~~h~~Heat Input ~~c~~Capacity of less than 40 MMBtu/hour that operates 200 hours or less per calendar year, or with an annual throughput limit equivalent to 200 hours per calendar year, shall be exempt from the requirements in:

(A) Subdivisions (d) provided:

(i) The ~~b~~Boiler has an enforceable South Coast AQMD permit condition~~s~~ that limits the operating hours to 200 hours or the annual throughput equivalent to 200 hours; and

(ii) The ~~b~~Boiler operates in compliance with the permit conditions pursuant to clause (n)(2)(A)(i~~i~~).

(B) Subdivisions (k) and (l) provided the ~~u~~Unit is not included in an approved B-Cap.

(3) Low-Use Process Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour

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An owner or operator of a ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour that is fired at less than 15 percent of the ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity on an annual basis, shall be exempt from the applicable emission limits in Table 1, Table 2, and an approved B-Plan.

(4) An owner or operator of a FCCU that must bypass the post-combustion air pollution control equipment to conduct ~~b~~Boiler inspections required under California Code of Regulations, Title 8, Section 770(b) shall be exempt from the applicable Rule 1109.1 Emission Limits during the required ~~b~~Boiler inspections.

(5) FCCU Startup Heater

An owner or operator of a ~~p~~Process ~~h~~Heater which is used only for startup of a FCCU and that ~~p~~Process ~~h~~Heater is operated for 200 hours or less per calendar year shall be exempt from the requirements in:

(A) Subdivisions (d) provided:

(i) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler has a South Coast AQMD permit that specifies conditions that limits the operating hours to 200 hours per calendar year or less; and

(ii) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler operates in compliance with the permit condition pursuant to clause (n)(5)(A)(i).

(B) Subdivisions (k) and (l) provided the ~~u~~Unit is not included in an approved B-Cap.

(6) Startup or Shutdown Boilers at Sulfuric Acid Plants

An owner or operator of a ~~p~~Process ~~h~~Heater used for startup or a ~~b~~Boiler used during startup or shutdown at a sulfuric acid plant that does not exceed 90,000 MMBtu of annual ~~h~~Heat ~~i~~Input per calendar year shall be exempt from the requirements in subdivisions (d), (i), (j), and (k) provided:

(A) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler has a South Coast AQMD permit that specifies conditions that limits the ~~h~~Heat ~~i~~Input to 90,000 MMBtu or lower per calendar year; and

(B) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler operates in compliance with the South Coast AQMD permit condition specified in subparagraph (n)(6)(A).

(7) Boiler or Process Heater Operating Only the Pilot

An owner or operator of a ~~b~~Boiler or ~~p~~Process ~~h~~Heater operating only the pilot prior to startup or after shutdown shall be exempt from the emission limits in paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 3, an approved B-Plan, or an approved B-Cap and may exclude those emissions from the rolling average calculation pursuant to Attachment A of this rule.

(8) Flares

(A) An owner or operator of a ~~f~~Flare that emits less than or equal to 550 pounds

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of NOx or less per year shall be exempt from the requirements in subdivisions (d), (g) and (k), provided:

(i) The ~~f~~Flare has enforceable South Coast AQMD permit conditions that limits the emissions to not exceed 550 pounds of NOx per year; and

(ii) The ~~f~~Flare is in compliance with the permit condition pursuant to clause (n)(8)(A)(i).

(B) An owner or operator of an open ~~f~~Flare, which is an unshrouded ~~f~~Flare, shall not be required to conduct source testing pursuant to subdivision (k).

(9) Vapor Incinerators

An owner or operator of a ~~v~~Vapor ~~i~~Incinerator that emits less than 100 pounds of NOx per year shall be exempt from the requirements in subdivision (d) provided the ~~v~~Vapor ~~i~~Incinerator:

(A) Has enforceable South Coast AQMD permit conditions that limit NOx emissions to less than 100 pounds of NOx per year through operating hours or annual throughput; and

(B) Operates in compliance with the permit condition pursuant to subparagraph (n)(9)(A).

Commented [A11]: Some references are to "year" and some are "calendar year"

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ATTACHMENT A

SUPPLEMENTAL CALCULATIONS

(A-1) Rolling Average Calculation for Emission Data Averaging

$$C_{Avg} = \sum_{i=t}^{t+N-1} C_i/N$$

Where:

C_{Avg} = The average emission concentration at time t

t = Time of average concentration (hours)

C_i = The measured or calculated concentration for a unit with a CEMS at the i^{th} subset of data; one-hour for a unit with an averaging time of 24 hours or less and 24-hour for a unit with an averaging time of greater than 24 hours

N = Averaging time (hours).

In order to calculate an average emission concentration at time t, the operator must have an elapsed operating period equal to or greater than time t.

(A-2) Interim NOx Emission Rate Calculation

An owner of operator shall calculate interim NOx emission rates as follows:

(A-2.1) Hourly Mass Emissions (lbs/hour)

Sum the actual annual mass emissions of all ~~boiler~~Boilers and ~~process~~Process ~~H~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour and any ~~boiler~~Boilers and ~~process~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour that operate a certified CEMS, and divide by 8760 hours for lbs per hour.

(A-2.2) Combined Maximum Heat Input (MMBtu/hour)

Sum the combined maximum ~~r~~Rated ~~h~~Heat ~~i~~Input for all ~~boiler~~Boilers and ~~process~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour and any ~~boiler~~Boilers and ~~process~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour that operate a certified CEMS.

(A-2.3) Interim Facility Wide NOx Emission Rate (lbs/MMBtu)

Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim NOx emission rate.

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ATTACHMENT B

CALCULATION METHODOLOGY FOR THE I-PLAN, B-PLAN, AND B-CAP

The purpose of this attachment is to provide details regarding how key elements of the I-Plan, B-Plan, and B-Cap are calculated. Key calculations provided in this attachment include: Baseline Unit Emissions and Baseline Facility Emissions; Final Phase Facility BARCT Emission Target; Total Facility NOx Emission Reductions; Phase I, Phase II, or Phase III Facility BARCT Emission Target; Phase I, Phase II or Phase III BARCT Equivalent Mass Emissions for a B-Plan; and Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap.

(B-1) Baseline Unit Emissions and Baseline Facility Emissions

Baseline Unit Emissions shall be determined by the Executive Officer based on the applicable 2017 NOx Annual Emissions Reporting data, or another representative year, as approved by the Executive Officer, expressed in pounds per year. Baseline Facility Emissions are the sum of all the Baseline Unit Emissions subject to this rule~~ and shall not include Baseline Unit Emissions for units that are operational on and after [DATE OF ADOPTION]~~.

Commented [A12]: Believe this was accidental. As written, would result in BFE = sum of BUE – sum of BUE = 0 (assuming no change in operating units).

BFE = Baseline Facility Emissions
BUE = Baseline Unit Emissions

(B-2) Final Phase Facility BARCT Emission Target

The Final Phase Facility BARCT Emission Target is the Phase II Facility BARCT Emission Target for an I-Plan option with two phases or the Phase III Facility BARCT Emission Target for an I-Plan option with three phases. The Final Phase Facility BARCT Emission Target is used to establish the Phase II or Phase III BARCT Emission Target for a B-Cap. To establish the Final Phase Facility BARCT Emission Target, the owner or operator must select whether~~if~~ the basis of the emission target for each ~~unit~~ Unit will be based on Table 1 or Table 2 NOx concentration limits. The owner or operator shall only select Table 2 NOx concentration limits if the requirements of subparagraphs (d)(2)(A) and (d)(2)(B) for the Conditional NOx Limits are met or if the ~~u~~Unit is identified pursuant to subparagraph (d)(2)(C) and ~~in~~ Attachment D. For all other ~~u~~Units, the owner or operator shall use NOx limits from Table 1 as the basis of the Facility BARCT Emission Target. To calculate the Final Phase Facility BARCT Emission Target for B-Cap, the owner or operator shall use NOx concentration limits from ~~of~~ Table 1 for the ~~u~~Units that will be decommissioned.

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(B-2.1) The Final Phase Facility BARCT Emission Target for a ~~facility~~ Facility complying with NOx emission limits in Table 1, an approved B-Plan or an approved B-Cap shall be calculated using the following equation:

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N	= Number of included ~~u~~Units in B-Plan or B-Cap
$C_{\text{Table 1 or Table 2}}$	= The applicable NOx concentration limit for each ~~u~~Unit i included in B-Plan or B-Cap
C_{Baseline}	= Representative NOx Concentration as defined in subdivision (c) for ~~u~~Unit i included in B-Plan
Baseline Unit Emissions	= Baseline Unit Emissions for ~~u~~Unit i as defined in subdivision (c) and included in the I-Plan, B-Plan or B-Cap as determined pursuant to section (B-1).

(B-3) Calculating Total Facility NOx Emission Reductions

Total Facility NOx Emission Reductions is the total reduction in NOx mass emissions per ~~facility~~Facility or ~~f~~Facilities ~~with~~ With ~~t~~The ~~s~~Same ~~o~~Ownership that would have been achieved if all ~~u~~Units met the NOx concentration limits in Table 1 or Table 2 of this rule based on the Baseline Facility Emissions.

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(B-3.1) For a ~~F~~facility complying with NOx emission limits in Table 1 or Table 2, an approved B-Plan or an approved B-Cap, the Total NOx Emission Reductions is the difference between Baseline Facility Emissions and the Final Phase Facility BARCT Emission Target.

Total Facility NOx Emission Reductions

= Baseline Facility Emissions

(B-4) Calculating Phase I, Phase II, or Phase III Facility BARCT Emission Target The Phase I, Phase II, or Phase III Facility BARCT Emission Targets are the total NOx mass emissions per ~~F~~facility based on the Total Facility NOx Emission Reductions and the Percent Reduction Target of Phase I, Phase II or Phase III of an I-Plan option in Table 6. ~~For a B-Cap, each phase Facility BARCT Emission Targets shall be reduced by 10 percent.~~

(B-4.1) For the B-Plan, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase I Facility BARCT Emission Target}_{\text{B-Plan}}$$
$$= \text{Baseline Emissions}$$
$$- (\text{Phase I Percent Reduction Target}$$

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(B-4.2) For the B-Cap, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions~~, less 10 percent~~.

$$\text{Phase I Facility BARCT Emission Target}_{B-Cap}$$
$$= [\text{Baseline Emissions}$$
$$- (\text{Phase I Percent Reduction Target}$$

(B-4.3) For the B-Plan, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase II Facility BARCT Emission Target}_{B-Plan}$$
$$= \text{Baseline Emissions}$$
$$- (\text{Phase II Percent Reduction Target}$$

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(B-4.4) For a B-Cap, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase II Facility BARCT Emission Target}_{B-Cap}$$
$$= [\text{Baseline Emissions}$$
$$- (\text{Phase II Percent Reduction Target}$$

(B-4.5) For a B-Plan, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.

$$\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Plan}$$
$$= \text{Final Phase Facility BARCT Emission Target}$$

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(B-4.6) For a B-Cap, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.

$$\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Cap} = (\text{Final Phase Facility BARCT Emission Target}) \cancel{\times 0.9}$$

(B-5) Calculating Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions for a B-Plan

The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies designed to meet Phase I, Phase II, or Phase III target reductions in an I-Plan. The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions incorporate the Alternative BARCT NOx Limit for Phase I, Phase II, or Phase III each of the ~~u~~Units included in different phases of the I-Plan. The Alternative BARCT NOx Limits are the ~~unit~~ Unit specific NOx concentration limit that are selected by the owner or operator in the B-Plan to achieve the Facility BARCT Emission Targets in the aggregate, where the NOx and CO concentration limits will include the corresponding percent O_2 correction based on the averaging time pursuant to Table 1 or subdivision (k), whichever is applicable. For the B-Plan, decommissioned units shall be removed from the Baseline Facility Emissions and the Facility BARCT Emission Targets.

(B-5.1) For a B-Plan, the Phase I BARCT Equivalent Mass Emissions for all units included in a B-Plan shall be calculated using the following equation:

$$\text{Phase I BARCT Equivalent Mass Emissions}_{B-Plan} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \right.$$

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× Baseline Unit Emissions)
i

Where:

N	=	Number of included units in B-Plan under Phase I
$C_{\text{Phase I Alternative BARCT Emission Limit}}$	=	The applicable Alternative BARCT NOx Limit in an approved B-Plan for unit i included in the B-Plan
C_{Baseline}	=	Representative NOx Concentration as defined in subdivision (c) for unit i included in the B-Plan
Baseline Unit Emissions	=	Baseline Unit Emissions for unit i as Defined in subdivision (c) and included in the B-Plan.

(B-5.2) For a B-Plan, the Phase II and if applicable, Phase III Equivalent Mass Emissions for each ~~u~~Unit included in a B-Plan shall be calculated using the equation for Section B-5.1, with the use of the Alternative BARCT NOx Limit for Phase II and Phase III, if applicable.

(B-6) Calculating Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap

The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies. The Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions must be at or below the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets an I-Plan. Under the B-Cap, there are three emission reduction strategies that can be used to meet the Facility BARCT Emission Targets: Establishing an Alternative BARCT NOx Limit, Decommission Units, and Reducing Throughput for Units. The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions calculation for the B-Cap acknowledges the three emission reduction strategies for each phase of the I- Plan. The Alternative BARCT NOx Limits are the ~~u~~Unit specific NOx concentration limits that are selected by the owner or operator in the B-Cap to achieve the Final Phase Facility BARCT Emission Target in the aggregate, where the NOx concentration limit will include the corresponding percent O_2 correction, CO emission limit, and averaging time per Table 1. The emission reductions from Decommission Units shall be incorporated in B-Cap pursuant to

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section (B-2.2). Other reductions in mass emission reductions to demonstrate that the BARCT B-Cap Annual Emissions include emission reductions from reduced throughput, efficiency, reduced capacity, and any other strategy to reduce mass emissions.

(B-6.1) The Phase I BARCT B-Cap Annual Emissions for each unit included in a B-Cap shall be calculated using the following equation where the Unit Throughput Reductions calculated pursuant to Section B-7.

$$\text{Phase I BARCT B} - \text{Cap Annual Emissions}_{B-Cap} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}}\right.$$

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$$\times \text{ Baseline Unit Emissions})_i$$
$$+ (0_{\text{Decommissioned Units}})_i$$
$$- (\text{Throughput or Other Reductions})$$

Where:

N = Number of included ~~u~~Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Cap for ~~unit~~ Unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~u~~Unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions as defined in subdivision (c) and for ~~u~~Unit i included in the B-Cap

Throughput or Other Reductions = Emission reductions occurred from other than reducing the concentration limit.

(B-6.2) For a B-Cap, the emission reductions the Phase II and if applicable, Phase III BARCT B-Cap Annual Emissions for each unit included in a B-Cap shall be calculated using the equation for Section B-6.1, with the use of three emission reduction strategies for Phase II and Phase III, if applicable.

(B-7) Emissions Reductions from Decommissioned Unit

For a B-Cap, emission reductions from decommissioned ~~u~~Units can be used to meet a Phase I, Phase II, or Phase III Facility BARCT Emission Target. The amount of emission reductions from a decommissioned ~~u~~Unit shall be determined using the equation below.

Emission Reductions from Decommissioned Units

$$= \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

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Where:

N	= Number of decommissioned ~~u~~Units in B-Cap
$C_{Table\ 1}$	= Table 1 NOx concentration limit for ~~u~~Unit i
$C_{Baseline}$	= Representative NOx Concentration as defined in subdivision (c) for ~~u~~Unit i included in an approved B-Cap
Baseline Unit Emissions	= Baseline Unit Emissions for ~~u~~Unit i as defined in subdivision (c) and included in an approved B-Cap.

(B-8) Unit Reductions for Conditional NOx and CO Limits in Table 2

An owner or operator of a ~~u~~Unit in a B-Plan that is demonstrating that the Unit Reduction is less than the thresholds specified in clauses (d)(2)(A)(i) or (d)(2)(A)(ii) shall calculate the Unit Reduction using the following equation:

$$\text{Unit Reduction} = \left(1 - \frac{C_{\text{Table 1}}}{C_{\text{Baseline}}}\right) \times \text{Baseline Unit Emissions}$$

Where:

$C_{Table\ 1}$	= The applicable Table 1 NOx concentration limit the unit
$C_{Baseline}$	= Representative NOx Concentration for the unit
Baseline Unit Emissions	= Baseline Unit Emissions.

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ATTACHMENT C

FACILITIES EMISSIONS – BASELINE AND TARGETS

(C-1) Baseline Facility Emissions

Table C-1 provides the Baseline Mass Emissions for Facilities with six or more units. Baseline Facility Emissions in Table C-1 are based on 2017 reported emissions for Rule 1109.1 units. A year other than 2017 was used for units where the 2017 reported emissions were not representative of normal operations.

TABLE C-1: Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017) (tons/year)
AltAir Paramount, LLC	187165	28
Chevron Products Co.	800030	701
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	386
Phillips 66 Co/LA Refinery Wilmington PL	171107	462
Tesoro Refining and Marketing Co., LLC – Carson	174655	636
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	674
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	8
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	899
Ultramar Inc.	800026	248
Valero Wilmington Asphalt Plant	800393	5

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT D

UNITS QUALIFY FOR CONDITIONAL LIMITS IN B-PLAN AND B-CAP

TABLE D-1: Units That Qualify for Conditional Limits in B-Plan

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
174655	D1465	427
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D159	176
800030	D160	176
800030	D161	176
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D384	48
800436	D385	24
800436	D388	147
800436	D388	147
800436	D770	63
800436	D777	146

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE D-2: Units That Qualify for Conditional Limits in B-Cap

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	D33	252
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D158	204
800436	D250	89
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

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PR 1109.1 - 54

Staff Response to Commenter Letter #6:

Response to Comment 6-1:

PR 1109.1 was revised to move the compliance dates in subdivision (d) – Emission Limits to subdivision (f) Compliance Schedule (formerly subdivision (g)). Staff retained the submittal dates for the I-Plan, B-Plan and B-Cap within their respective subdivisions.

Response to Comment 6-2:

Staff agrees that the term "deemed complete" is a very specific term within the South Coast AQMD permitting process. PR 1109.1 does not use the term "deem complete" but references a complete permit application, meaning all necessary elements are included in the permit application. PR 1109.1 has been revised to "submit a complete permit application" and a discussion has been added in the staff report that further explains that a "complete permit application" does not mean that the permit application has been "deemed complete."

Response to Comment 6-3:

Any unit that is listed in Table D-1 or Table D-2 must submit a permit application based on the schedule in an approved I-Plan. In addition, Units identified in Table D-1 and D-2 may have an alternative BARCT NOx limit higher than the Table 2 conditional NOx concentration limits. Units in Table D-1 are units staff identified as qualifying for the Table 2 conditional NOx concentration limits. These units had high cost-effectiveness values because they either had a low emission reduction potential because units were operating close to the Table 1 NOx concentration limit or had high capital costs. Units in Table D-2 are for those operators that select a B-Cap compliance option with I-Plan Option 4. Units in Table D-2 have annual average NOx concentrations based on representative data that is at or below 25 ppm. Although operators are limited to the units listed in Table D-2, operators can establish an alternative BARCT NOx concentration limit for units listed in Table D-2 during implementation of the I-Plan and establish an alternative BARCT NOx concentration limit higher than the Table 2 conditional NOx concentration limits provided it does not exceed the maximum alternative BARCT NOx concentration limits for a B-Cap pursuant to Table 6 of PR 1109.1. I-Plan Option 4 is unique compared to the other I-Plan options as it requires a 50 percent reduction by January 1, 2024 which will achieve NOx reductions six months earlier than operators that are meeting Table 2 conditional NOx concentration limits under subparagraph (f)(3) (assuming 18 months for the Executive Officer to issue a permit to construct and 18 months to meet the NOx limit). In addition, although NOx concentration limits may be higher than the limits in Table 2 for units listed in Table D-2 of PR 1109.1, operators under the B-Cap have the additional obligation to demonstrate that actual emissions are below the facility BARCT emission target.

Operators that do not meet the criteria for units listed in Table D-1 or Table D-2, must establish a NOx limit that is at or below Table 2 conditional NOx limits. Conditional NOx limits were developed to help reduce the average cost-effectiveness and to address units with the worst cost-effectiveness. In addition to the units staff identified through the cost-effectiveness analysis (Table D-1 Units) and units in a B-Cap that will use I-Plan Option 4 (Table D-2 Units), PR 1109.1 allows operators to identify units that can meet Table 2 conditional NOx limits, that meet the conditions of paragraph (d)(3). This provision was added to recognize that there may be additional units that can achieve the Table 2 conditional NOx limits that have existing pollution controls and can make minor modifications to the existing pollution controls, if any, to meet the Table 2 conditional NOx limits. Use of Table 2 conditional NOx limits will increase the facility BARCT emissions target. Staff believes that operators that use a conditional NOx limit beyond what is assumed in the cost-effectiveness analysis should be held to the conditional NOx limit. If the operator cannot meet the conditional NOx limit within the time allowed under PR 1109.1, then the unit likely needed additional pollution controls and should then be required to meet the Table 1 NOx concentration limit.

The rule does provide some flexibility in regard to the Table 2 conditional limits. Any unit that is listed in Table D-1 or Table D-2 must submit a permit application based on the schedule in an approved I-Plan. In addition, units identified in Table D-1 and D-2 may have an alternative BARCT NOx limit higher than the Table 2 conditional NOx concentration limits.

Response to Comment 6-4:

One of the most important conditional provisions for using the Table 2 conditional NOx concentration limits is to ensure units with new SCR installations meet Table 1 NOx concentration limits. Most SCR installations permitted under the RECLAIM program do not include NOx permit limits; therefore, the rule language change requested by WSPA would allow most new SCR installation to elect to comply with the Table 2 Conditional limits even though the new SCRs should be able to achieve Table 1 limits. The third-party engineering consultant, Norton Engineering, concluded that LNBs can achieve 40 – 50 ppmv NOx concentrations under non-optimal conditions and up to 30 ppmv NOx under optimal conditions. Norton Engineering also stated a single bed SCR can achieve at least 92% NOx emission reductions; however, using multiple catalyst bed with additional ammonia injection grid can increase the NOx emission reductions to above 94%. Considering the emission reduction capability of NOx control technologies, it is reasonable to expect units where the permit to construct was issued after 2015, will consequently benefit from the installation of modern control technologies that can achieve Table 1 NOx concentration limits. There are also alternative plans in the rule that allow facilities to use a higher NOx concentration limit than Table 1 NOx limits. Considering the flexibility provided in the PR 1109.1 allowing for alternative plans, a unit is not tied to meet a specified endpoint. In addition, the 2015 NOx shave BARCT assessment, which was based on a programmatic BARCT assessment, concluded a 2 ppmv NOx limit is technically feasible and cost-effective, as did the initial BARCT assessment under PR 1109.1. Facilities should have been striving to achieve 2 ppmv NOx for all units with new SCR installations. Staff is concerned that allowing facilities to meet Table 2 conditional NOx limits for units with new SCR installation would create a significant loophole which can lead to weakening of PR 1109.1. Based on the reasons cited above and the rule construct, staff does not believe any newly installed SCR will have to be replaced; therefore, there will not be any stranded assets for recently installed NOx control equipment.

Response to Comment 6-5:

Staff concurs with this comment and revised this provision.

Response to Comment 6-6:

Staff acknowledges that there are two process heater that do not currently meet the 40 ppmv proposed limits. Staff presented the cost-effective assessment for those units to retrofit to 40 ppmv in Appendix B of the staff report and revised the main body of the staff report to reflect that analysis. The compliance dates for the process heaters were revised in the draft rule to accommodate those units that will require the installation of controls. PR 1109.1 has the following pathways for the process heaters <40 MMBtu/hour to comply with the 40 ppmv NOx and interim limits:

Interim limit:

- Comply with the 0.03 pound/MMBtu facility-wide emission rate for any boiler or process heater <40 MMBtu/hour that operates with a certified CEMS;
- Facilities complying with a B-Cap will comply with the interim cap instead of the interim limits; or
- Comply with the new interim limit of 60 ppmv for process heaters <6 MMBtu/hour.

40 ppmv NOx limit:

- Comply with the limit based on the revised schedule in (f)(2)
- Comply with the limit based on the schedule in the I-Plan where the facility BARCT emission target for that unit is based on:
  - 40 ppmv if the unit is included in phase I of the I-Plan and no further emission reduction credit is taken for the unit in phase II or phase III; or
  - 9 ppmv if the unit is included in any phase other than phase I.

Response to Comment 6-7:

Please see the response to comment 6-6 and the BARCT assessment in Appendix B.

Response to Comment 6-8:

Please see the response to comment 6-6.

Response to Comment 6-9:

Staff did conduct and present the BARCT assessment for boilers and process heaters to meet the 5 ppmv and 9 ppmv NOx limits in Working Group Meeting #9. The assessment concluded those NOx limits are cost effective if the limits are effective upon burner replacement. The 5 ppmv NOx limits for boilers has been demonstrated in practice; however, the 9 ppmv limit for process heaters is a technology forcing limit. The BARCT emission levels can be technology forcing NOx concentration limits, meaning the limits can be based on emerging technology provided the NOx limit is achievable by the compliance date. Emerging technology is technology that can achieve emission reductions but is not widely available at the time the NOx limit is established and the rule is adopted. When South Coast AQMD adopts rules with technology forcing emission limits, the limits are given a future implementation date to allow time for the technology to develop. BARCT limits evolve over time as technology improves or new pollution control technologies emerge; setting future effective emission limits is appropriate and the approach has been used, and upheld, in other rules. South Coast AQMD adopted volatile organic compound (VOC) limits in Rule 1113 – Architectural Coatings in 2002 with a future effective date of July 1, 2006 based on emerging technology (e.g., reformulated coatings). The technology to meet the lower VOC limits was commercially available but had performance issues that had yet to be overcome. The American Coating Association sued the South Coast AQMD for adopting technology forcing BARCT limits, but the South Coast AQMD prevailed in the Supreme Court of California upholding the ability to adopt technology forcing BARCT limits.

Further, staff believes the implementation of the B-Plan and B-Cap in PR 1109.1 will help incentivize operators to accelerate introduction and commercialization of emerging technologies. Staff will monitor the development of the emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized.

Response to Comment Response 6-10:

Staff does not agree with this comment. Units in both the B-Plan and the B-Cap that meet the conditions for the Table 2 are held to the Table 2 conditional NOx limits unless the units are listed in Table D-1 or Table D-2 where a facility can elect to assign a higher NOx limit than Table 2 when establishing the facility BARCT emission target, provided the facility offsets those higher limits with units that are over controlled. In a B-Cap, facilities are allowed to take "credit" from decommissioned units, so PR 1109.1 includes additional limitations when selecting the alternative BARCT NOx limits. Requiring all units to meet either the maximum NOx limits or the Table 2 conditional limits ensures all units have some level of NOx emission controls.

Response to Comment 6-11:

Staff disagrees with this comment. PR 1109.1 only allows a facility to take "credit" for decommissioned units if they are complying with a B-Cap. In a B-Cap, emission reductions associated with decommissioned units allow other units within the B-Cap to establish a higher alternative BARCT NOx limit and have higher NOx mass emissions. PR 1109.1 requires the facility BARCT emission target for decommissioned units to be calculated based on the applicable Table 1 NOx emissions to minimize the amount of "credit" generated from the decommissioned unit that can be used to offset emission reductions that otherwise would have been required. In addition, since units that can use Table 2 conditional limits are already performing under those limits, allowing facilities to use Table 2 conditional NOx limits to establish the facility BARCT emission targets for decommissioned units under B-Cap would create extra emission reduction "credits" in B-Cap and decrease the overall emission reductions.

Response to Comment 6-12:

Under the B-Cap, an operator can decommission or shutdown units to meet the facility BARCT emission target. If a facility were to decommission a unit, the emissions budget for that decommissioned unit can be used to have a higher alternative NOx concentration limit for another unit. Operators that decommission more units will be able to select higher alternative NOx concentration limits on more units, as compared to an operator with little or no decommissioned units. In addition, each unit under the B-Cap will receive an emissions budget. Units that are decommissioned will have an emissions budget in the facility BARCT emissions target based on the NOx concentration limit in Table 1. Safeguards are needed to ensure an operator that is adding a new unit is not receiving an increase in the B-Cap and the emissions budget. It would not be equitable that the emissions budget from a decommissioned unit was used to allow another unit not to install pollution controls, and later, install a unit that is functionally similar to the unit that was decommissioned. PR 1109.1 does not preclude an operator from adding New Units, but rather, the rule requires certain conditions be met if a New Unit subject to PR 1109.1 is installed. PR 1109.1 has been modified since the preliminary draft staff report and prevents an operator installing a new unit unless:

- The BARCT equivalent mass emissions are below the facility BARCT emission target for each phase of the I-Plan;

- The new unit is not functionally similar to any unit that was decommissioned in the approved B-Cap;
- The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of final phase facility BARCT emission target in an approved B-Cap; or
- The new unit is functionally similar to any unit that was decommissioned and is included in the BARCT B-Cap annual emissions with no increase in the facility BARCT emission target.

Response to Comment 6-13:

Staff concurs and revised the requirements to clarify that two interim emission limits do not apply to boilers and process heaters < 40 MMBtu/hour.

Response to Comment 6-14:

Staff concurs with this suggestion and restructured the rule language.

Response to Comment 6-15:

Staff disagrees with this comment as approval of the I-Plan, B-Plan, and B-Cap will require more than just ensuring the facilities provided all of the required elements. South Coast AQMD must also ensure the alternative BARCT NOx limits, facility BARCT emission targets, BARCT equivalent mass emissions and BARCT B-Cap annual emission were calculated correctly and based on reasonable assumptions. There are many variables in PR 1109.1 plans, approval is not just an administrative approval process.

Response to Comment 6-16:

Staff clarified the language to indicate that PR 1109.1 requires source testing quarterly during the first 12 months of being subject to the NOx concentration limit, and operators can source test annually thereafter provided the operator had four consecutive quarterly source tests to demonstrate compliance with CO, NOx, and ammonia concentration limit. The intent was not to require quarterly testing thereafter. This source testing schedule is consistent with Rule 1134 – Turbines and Rule 1146 – Boilers and Process Heaters. Units at petroleum refineries and at facilities with related operations to petroleum refineries should not have more lenient source test requirements than other facilities.

Response to Comment 6-17:

Staff disagrees with this comment. While some NOx landing rules were initially adopted with ammonia limits, staff decided to remove the ammonia limits from the source-specific rules and allow operators to establish the ammonia concentration limit during permitting. Although ammonia concentration limits have been removed from source-specific rules, the source testing requirement was retained in these rules. In addition, all recent NOx landing rule are being adopted without ammonia limits but including ammonia source testing schedules similar to what is being proposed in PR 1109.1.

Response to Comment 6-18:

Staff concurs and revised this section.

Response to Comment 6-19:

Based on discussions with U.S. EPA and review of U.S. EPA's January 2001 guidance for EIPs titled "Improving Air Quality with Economic Incentive Programs" referred herein as "EIP Guidance," the B-Cap is an Economic Incentive Program (EIP). Section 1.2 of the EIP Guidance states that, "You should follow this guidance if you are developing an EIP that you intend to include in a SIP as a means of achieving emission reductions to meet your SIP or SIP related requirements or as a means for providing sources with compliance flexibility for existing SIP requirements." The B-Cap is a discretionary EIP that was developed to provide compliance flexibility in achieving greater emission reductions than those that would occur if the operator were to meet the specified NOx concentration limits in Table 1 and the conditional NOx concentration limits allowed under Table 2. This additional compliance flexibility is added to help address the high capital cost associated with installation of pollution controls needed to meet NOx limits under PR 1109.1. This is consistent with the purpose of an EIP which is to allow sources compliance flexibility to meet SIP requirements more cost effectively.

The B-Cap is a combination of an emissions averaging and a source-specific cap and trade EIP. The B-Cap is an emission averaging program EIP as it allows operators to select an alternative BARCT NOx limit for each unit and requires the operator to demonstrate that mass emissions for all units in the B-Cap are in aggregate, below the Facility BARCT Emission Target. It is also a source-specific cap and trade EIP as it allows all units within the B-Cap alternatively demonstrate compliance with Table 1 and Table 2 NOx concentration limits through a mass-based emissions cap and applies to one facility with more than one owner and applies only to stationary sources. The B-Cap addresses equipment categories or units that must operate under a mass emissions cap and allows a variety of emission reduction strategies to demonstrate that mass emissions are below the mass cap or facility BARCT emission target. Use of the different emission reduction strategies include lowering the NOx concentration limit of individual units, shutting down individual units, and other emission reduction strategies such as reduction in throughput, increased efficiency, reduction in capacity, and any strategy that can reduce mass emissions. Use of these various emission reduction strategies allows for other units within the B-Cap to have higher NOx concentration limits for individual units.

The B-Cap is a trading EIP. An emissions averaging program and a source cap and trade program are both trading EIPs. Section 7.1 of the EIP Guidance defines a trading EIP as "a program that involves at least two emission units." The EIP Guidance explains that a trading EIP is where one emission unit with an emission reduction obligation uses emission reductions at different emission unit to meet these emission obligations. The EIP Guidance specifically states that, "There are four main types of emission trading programs: Emission averaging; Source-specific emission caps; Multi-source emission cap-and-trade; Open market trading." By allowing units to make greater emission reductions on some units to allow less emission reductions for other units to meet the facility BARCT emission target, the B-Cap is consistent with an emissions trading EIP.

For compliance flexibility EIPs, an environmental benefit means reducing the amount of surplus emission reductions generated for use in the EIP by at least 10 percent. The EIP Guidance does require that all EIPs demonstrate an environmental benefit. PR 1109.1 includes a 10 percent environmental benefit for the B-Cap that increases the facility emission reductions for each phase by 10 percent. Staff agrees that the EIP Guidance requires that a trading EIP in a nonattainment area that is needing and lacking an approved attainment demonstration (NALD) to incorporate an extra 10 precent reduction in emissions as the environmental benefit. Staff does not agree that the

EIP Guidance prohibits a trading EIP that is not a NALD to incorporate a 10 percent reduction in emissions as an environmental benefit. Section 4.3 of the EIP Guidance states, that a trading EIP that does not cover nonattainment areas that are NALD "can require a 10 percent extra reduction in emissions, or it can implement other provisions." Based on discussions with U.S. EPA, for the B-Cap, it was decided that reducing the Facility BARCT Emission Target by 10 percent is the most appropriate environmental benefit for the B-Cap since PR 1109.1 is designed to reduce NOx emissions, and NOx emission reductions are needed as NOx is a precursor to ozone, and the South Coast Air Basin is designated as extreme nonattainment with the ozone National Ambient Air Quality Standard.

The I-Plan does not achieve greater or more rapid emission reductions since the I-Plan provides an alternative to submitting a permit application for each unit before July 1, 2023, which is the baseline for evaluating rapid emission reductions. Staff agrees that implementation of I-Plan Option 4 does require a 50 percent of the required reductions by January 1, 2024. However, I-Plan Option 4 has two additional compliance dates to submit permit applications by January 1, 2025 and January 1, 2028 which is well after the July 1, 2023 compliance date in PR 1109.1 paragraph (d)(1). Incorporating a provision that would show greater or more rapid emission reductions that are more aggressive than PR 1109.1 paragraph (d)(1) would be very challenging for operators, and therefore, this option was not suggested as an environmental benefit.

The EIP Guidance Section 7.3(a) states that it must be demonstrate that "your EIP has resulted in more reductions than would have occurred without the program." The baseline for determining surplus emission reductions is direct compliance with meeting the NOx limits in Table 1 and the conditional NOx limits in Table 2 since the B-Cap is an alternative to meeting the NOx limits in Table 1 and Table 2. If an operator were to meet the NOx limits in Table 1 and Table 2, there is no "credit" for units that are decommissioned. Emission reductions from a decommissioned unit would be in addition to the NOx reductions that would be achieved from meeting the NOx limits in Table 1 and Table 2. Although units that are permanently decommissioned and not replaced with a functionally similar unit will reduce NOx and other pollutants, emission reductions from decommissioned units are not an environmental benefit relative to the baseline reductions associated meeting the NOx limits in Table 1 as specified in paragraph (d)(1) and the conditional NOx limits in Table 2 as specified in subparagraphs (d)(2)(A) and (d)(2)(B).

Under the B-Cap, emission reductions associated with decommissioned units allows other units within the B-Cap to establish a higher alternative NOx emission limit and have higher NOx mass emissions. The increase in mass emissions for the other units in the B-Cap will accordingly also have co-pollutant emission increases, which eliminates any benefit associated with the decommissioned unit and therefore would not be an appropriate demonstration of an environmental benefit. Specifically requiring an additional 10 percent reduction of the BARCT facility emission target ensures that an environmental benefit of NOx emission reductions will occur.

The South Coast AQMD has the obligation to ensure that PR 1109.1 can be approved by CARB and U.S. EPA to be incorporated into the State Implementation Plan (SIP). Staff has discussed the provisions of the B-Cap with both agencies and they concur that the additional 10 percent reduction in the BARCT facility emission target is appropriate for the B-Cap.

Response to Comment 6-20:

Staff appreciates the comments on the rule language and took them under consideration.

Comment Letter #7:

Tesoro Refining &
Marketing Company LLC
A subsidiary of Marathon Petroleum Corporation

Los Angeles Refinery – Carson Operations
2350 E. 223rd Street
Carson, California 90810
310-816-8100

September 17, 2021

VIA Certified Mail and eMail (*wnastri@aqmd.gov*)
Return Receipt Requested

Wayne Nastri
Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on SCAQMD Preliminary Draft Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries – And Related Proposed Rule 429.1 and Proposed Amended Rules 1304 and 2005 (Revision Date: August 20, 2021)

Dear Mr. Nastri:

On behalf of Tesoro Refining & Marketing Company LLC, a wholly owned subsidiary of Marathon Petroleum Corporation (collectively, "MPC"), MPC appreciates this opportunity to provide South Coast Air Quality Management District (SCAQMD) with comments on the Preliminary Draft Proposed Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (PR 1109.1) and the related proposed amended rules that were issued by the SCAQMD on August 20, 2021 (i.e., Proposed Rule 429.1 and Proposed Amended Rules 1304 and 2005).[1] Throughout the rulemaking process, MPC staff continues to be active participants in PR 1109.1 working group meetings and discussions with SCAQMD staff.

This set of comments, which supplements MPC's four previous comment letters submitted to SCAQMD on December 22, 2020, February 1, 2021, April 7, 2021, and May 12, 2021, focuses on several concerns that we outline below. Attachment 1 of this letter is a proposed mark-up of PR 1109.1 in red-line format that corresponds to MPC's comments.

1. **If U.S. EPA's Environmental Incentive Programs (EIP) Guidance[2] is applicable to the Best Available Retrofit Control Technology (BARCT) Equivalent Mass Cap Plan (B-Cap), environmental benefit can be demonstrated by other options and not only by the currently** 7-1

[1] SCAQMD, "Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pd_pr1109-1_75 da y.pdf?sfvrsn=6
[2] EIP Guidance https://www.epa.gov/sites/default/files/2015-07/documents/eipfin.pdf

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proposed additional 10% reduction in the mass oxides of nitrogen (NOx) Emission Targets in PR 1109.1. 7-1 (cont'd)

A. U.S. EPA's EIP Guidance does not apply to the B-Cap

As currently drafted, PR 1109.1 at subparagraph (g)(2)(C) includes a 10% reduction (environmental benefit) in Phase I, Phase II, and Phase III Facility BARCT Emission Targets for a Facility that decides to comply with the B-Cap option. MPC understands that the U.S. EPA has not affirmed that the B-Cap is subject to the requirements of U.S. EPA's January 2001 guidance document entitled "Improving Air Quality With Economic Incentive Programs" (EIP Guidance) and is currently evaluating the applicability of the EIP Guidance to the B-Cap.[3] U.S. EPA's EIP Guidance indicates that the B-Cap is not an Economic Incentive Program (EIP). For example, when describing the types of discretionary EIPs, the EIP Guidance includes statements such as the following:

- An EIP may be an emission trading program, a financial mechanism program, a program such as a clean air investment fund (CAIF) that has features of both trading and financial mechanism programs, or a public information program.[4]

- The four general types of EIPs are emission trading programs, financial mechanisms, CAIFs, and public information programs.[5]

- Unlike traditional CAA regulatory mechanisms, emission trading involves more than one party.[6]

Since the B-Cap does not involve trading, and clearly does not qualify as any of the other types of EIPs covered by the EIP Guidance, the B-Cap should not be subject to review under the EIP Guidance.

B. U.S. EPA's EIP Guidance allows flexibility for demonstrating environmental benefit 7-2

If U.S. EPA, however, ultimately determines that EIP Guidance applies to the B-Cap, the guidance allows flexibility to demonstrate the environmental benefit which can be something other than reducing surplus mass NOx emissions by at least 10%. Indeed, there are already multiple environmental benefits inserted into the B-Cap and I-Plan requirements as we explain below. "Environmental benefit" is defined as follows:

> *Environmental benefit generally means ... increased or more rapid emission reductions. ... environmental benefit means reducing the amount of surplus emission reductions generated for use in the EIP by at least 10 percent. In addition, environmental benefit can also mean improved administrative mechanisms (e.g., that achieve emissions reductions from sources not readily controllable through traditional regulation), reduced administrative burdens on regulatory agencies that result in increased environmental benefits through other regulatory programs, improved emissions inventories that enhance and lend increased certainty to State planning efforts, and the adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches.*

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[3] SCAQMD states in its Draft Staff Report that "*U.S. EPA has initially commented that pursuant to U.S. EPA's January 2001 Improving Air Quality with Economic Incentive Programs, a 10 percent environment benefit will likely be required. Staff is continuing to discuss the elements of the B-Cap with U.S. EPA.*" (Draft Staff Report at p. 3-15)

[4] *Id.* at p. 15

[5] *Id.* at p. 18

[6] *Id.* at p. 78

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While the EIP Guidance requires demonstration of environmental benefit, the guidance "recognizes that the type of demonstration appropriate will depend on the goals and characteristics of the EIP [being] implemented."[7]

Furthermore, should the B-Cap be considered as a compliance flexibility trading EIP covered by the EIP Guidance, there are other sections of the EIP Guidance which indicate that the environmental benefit associated with a compliance flexibility trading EIP is not required to be a surplus 10% emission reduction, but may be an alternative demonstration as long as the EIP does not cover a nonattainment area that is needing and lacking an attainment demonstration, known as a "NALD area". As discussed below, South Coast AQMD is not an "NALD area" and therefore has flexibility to allow alternatives.

"NALD areas" are defined as follows:

> *Needing and lacking demonstration (NALD)--means a non-attainment area for which a State is currently required under the CAA to submit an SIP for attainment demonstration, but has not done so.*[8]

The SCAQMD has submitted, and EPA has approved, multiple ozone attainment demonstrations for the South Coast Air Basin, including most recently the 2016 Air Quality Management Plan ("2016 AQMP"), which states as follows:

> *The 2016 AQMP demonstrates how and when the South Coast Air Basin, as well as the Coachella Valley, will attain the ozone and PM2.5 standards as "expeditiously as practicable," but no later than the latest statutory attainment date.*[9]

7-2 (cont'd)

Therefore, the South Coast Air Basin is not a "NALD area" in which an alternative environmental benefit would be prohibited under the EIP Guidance.

Other options for meeting the environmental benefit requirement in the EIP Guidance include the following, some of which are already embedded within the rule framework of the B-Cap and I-Plan as noted in brackets:

- *showing greater or more rapid emission reductions due to trading (e.g., early reductions)* – [The I-Plan for B-Cap Facilities includes a provision for earlier reductions by January 1, 2024 of at least 50% of the total required emission reduction under PR 1109.1 as compared to the schedule for meeting the limits in Tables 1 and 2.]

- *showing other environmental management improvements* – [A Facility that permanently decommissions a Unit and not replacing it with a functionally similar Unit or that reduces its annual throughput or NOx concentration to meet the B-Cap will deliver other important emissions reductions to the South Coast Air Basin beyond NOx, including other criteria pollutants such as VOC, SO_2, and fine particulate matter, as well as benefiting AB-617 communities.]

[7] *Id.* at p. 56
[8] *Id.* At p. 108
[9] 2016 AQMP at p. ES-10

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- *improved administrative mechanisms (for example, your EIP achieves emissions reductions from sources not readily controllable through traditional regulation)*

- *reduced administrative burdens on regulatory agencies that lead to increased environmental benefits through other regulatory programs*

- *improved emissions inventories that enhance and lend increased certainty to State planning efforts*

- *the adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches* – [The B-Cap contains restrictions on how new Units are to be added such that a Facility's NOx emissions are less than the Facility's Emission Targets.]

- *for multi-source cap and trade program or a single source cap and trade program, includes a declining cap.* 7-2 (cont'd)

These provisions make clear that alternative environmental benefits are permissible under the EIP Guidance under certain circumstances. Moreover, some of these alternative environmental benefits allowed for under the EIP guidance are already included in the B-Cap and I-Plan as currently drafted, including an accelerated schedule for achieving the majority of the NOx emissions reductions well in advance of what is otherwise required without a B-Cap. Additionally, collateral emissions reductions in other criteria and toxic air pollutants will result from decommissioning and/or reducing the annual utilization or throughput of equipment to meet the B-Cap that improve emissions inventories, represent an emissions cap that constrains or reduces growth-related emissions, and includes a declining cap.

Therefore, if it is ultimately determined by U.S. EPA that the EIP Guidance does indeed apply to the B-Cap, the B-Cap and I-Plan framework for both early emissions reductions as well as collateral pollutant emissions reductions satisfies this environmental benefit obligation as described above. To ensure the rule credits a Facility for these environmental benefits, MPC proposes a new subparagraph (i)(3)(H) and other rule revisions in Attachment 1 of this letter that require a Facility electing to comply with a B-Cap to demonstrate environmental benefit using allowable options in the EIP Guidance.

2. Regulatory certainty is necessary to demonstrate that emission reduction projects will not trigger Federal New Source Review for PM_{10} or $PM_{2.5}$.

As SCAQMD understands, many of the proposed low NOx BARCT limits under PR 1109.1 cannot be achieved without selective catalytic reduction (SCR). MPC and other stakeholders have previously pointed out that installation of SCR may result in increases in emissions of particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) (PM_{10} and $PM_{2.5}$ collectively referred to as "fine particulate matter") such that the retrofit project could trigger a "major modification" under U.S. EPA's New Source Review (federal NSR) program, and thus require Best Available Control Technology (BACT).[10] 7-3

[10] See MPC's Fourth Set of Comments on SCAQMD Revised Draft of Proposed Rule 1109.1-Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (Revision Date December 24, 2020) (dated May 12, 2021). MPC previously provided data from emissions testing using reference test methods at a heater with SCR technology to reduce NOx emissions. The resulting emissions factor for fine particulate matter, when combined with the heater input duty and a lower fine particulate matter emissions factor to represent pre-SCR baseline operations, may result in a significant emissions increase subject to the 40 CFR §52.21 and/or SCAQMD 1325 as a major modification.

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In SCAQMD's Preliminary Draft Staff Report for Proposed Amended Rules 1304 and 2005, SCAQMD states:

> *For the purpose of determining federal major NSR applicability, PM and SOx emission increases may be estimated according to the calculations below. The following approach to calcualte [sic] PM and SOx emissions for the purpose of determining NSR applicability has been discussed without opposition with U.S. EPA.*
>
> * * *
>
> *The calculation method will be used in lieu of conducting a source test for PM_{10} emissions when a facility submits a permit application for SCR installation or modification.*

SCAQMD also provides an example calculation for determining the ammonium sulfate as fine particulate matter that may form as a result of installing SCR.[11] 7-3 (cont'd)

For reference, the South Coast Basin is designated in attainment with the PM_{10} NAAQS and is subject to 40 CFR § 52.21 for the Prevention of Significant Deterioration (PSD) permit program. SCAQMD Rule 1325 - Federal $PM_{2.5}$ New Source Review Program – applies to new and modified major sources that trigger the federal NSR threshold for $PM_{2.5}$. Rule 1325 incorporates and adopts U.S. EPA requirements for $PM_{2.5}$, which is designated nonattainment with the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). Nowhere in Rule 1325 has this alternative calculation method been incorporated, referenced, or proposed to be added as part of PR 1109.1. If PR 1109.1 is approved in its current form and the alternative calculation method for determining fine particulate matter is only referenced in SCAQMD's Draft and Final Staff Report and not incorporated into Rule 1325, MPC is concerned that U.S. EPA cannot accept this alternative calculation method and shall require the use of U.S. EPA test methods that are referenced in Rule 1325 to demonstrate that an SCR project has not exceeded the federal major NSR threshold prior to issuance of the permit to construct.

The significance of having a federal major NSR determination for fine particulate matter is the additional amount of time (multiple years) a Facility would need to complete the permitting process as well as potentially requiring BACT for PM_{10} emissions or lowest achievable emission rate (LAER) for $PM_{2.5}$ emissions. In the case of MPC's Los Angeles Refinery, LAER technology for $PM_{2.5}$ could be a fuel gas sulfur treatment project that would add over $100 million in costs. Moreover, this additional cost to comply with PR 1109.1 has not been considered by SCAQMD in the cost-effectiveness of NOx BARCT.

3. Compliance schedules should be dependent on the issuance date of a Permit to Construct, and not on the date of permit application submittal.

Some of the key compliance deadlines in PR 1109.1 for meeting emissions limits and to complete emissions reduction projects are based on a specified duration of time after the Facility submits its Permit to Construct application instead of being based on a time frame after issuance of a Permit to Construct by the SCAQMD. A Facility cannot commence and complete emissions reduction projects for PR 1109.1 without having a Permit to Construct issued by SCAQMD. There are no deadlines or time frames in PR 1109.1 that SCAQMD must meet for issuing a permit after an application has been submitted. As a result, a Facility may not be able to meet a compliance deadline if SCAQMD does not issue an air permit in a timely manner. Based on historical projects, SCAQMD can take several years to issue a Permit to 7-4

[11] SCAQMD, "Preliminary Draft Staff Report, Proposed Amended 1304 - Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/pdsr-par-1304_2005-aug-2021.pdf?sfvrsn=16, pages 2-6 and 2-7

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Construct, and the facility has no certainty when the permit will be ultimately issued. Therefore, any deadlines in PR 1109.1 that are currently in the rule language based on permit application submittal dates should be changed to a time frame after issuance of the permit(s). MPC requests the following deadlines and corresponding language be changed or removed in PR 1109.1:

- Subparagraph (g)(2)(I) contains a compliance date for an approved B-Cap that is *"... no later [than] 54 months from South Coast AQMD Permit Application Submittal Date for all other phases of the selected I- Plan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets."* Since Table 6 already lists compliance dates that are either a specific date or based on permit issuance, this requirement is unnecessary.

- Paragraph (g)(5) requires a Unit complying with certain emission limits in subdivision (d) and that fails to submit a complete permit application by the specified date in PR 1109.1 to *"... meet the applicable Rule 1109.1 Emission Limits no later than 36 months after the South Coast AQMD permit application submittal date."* This provision is effectively requiring a facility to commence construction on projects necessary to meet PR 1109.1 without a Permit to Construct being issued by SCAQMD if the permit is not issued within a certain time frame, thus potentially forcing non-compliance that is outside the facility's control. Other requirements in PR 1109.1 establish when these limits shall be met following issuance of a Permit to Construct. Those should remain in the case that a complete permit application is not submitted by the specified date in PR 1109.1. Paragraph (g)(5) should be removed in its entirety. 7-4 (cont'd)

Related to the compliance schedule language in subdivision (g), subparagraphs (g)(2)(B) through (G) do not provide a compliance date and are duplicating the required elements in subdivision (i) for Plan submittals. Since subparagraph (g)(2)(A) already references provisions in subdivision (i) and the corresponding compliance date, MPC requests removal of subparagraphs (g)(2)(B) through (G) because they are duplicative and confusing.

4. The compliance date in PR 1109.1 for emission limits with multi-day rolling average periods should be clarified to represent the first day of the rolling average period.

PR 1109.1 contains some emission limits that have multi-day rolling average periods, such as concentration limits on a 7-day rolling average or 365-day rolling average as well as mass emission limits on a 365-day rolling total (i.e., Facility BARCT Emission Target). The compliance date in PR 1109.1 for these longer averaging periods represents the first day of measuring or calculating emissions such that after the last day of the limit's averaging period, the first compliance demonstration is made. For example, Table 6 for I-Plan Option 4 lists a date of January 1, 2024 as the compliance date for meeting the Phase I BARCT Emission Target. The first demonstration of compliance with the tons-per-year BARCT Emission Target will be after December 30, 2024, which is 365 days from January 1, 2024, noting that 2024 is a leap year with 366 days. 7-5

This clarification should be made for all multi-day rolling average periods, and MPC recommends adding a definition in subdivision (c) for "Compliance Date" that reflects this. See Attachment 1 for proposed language to define this term.

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5. The CO limit overlap provision in paragraph (d)(7) should extend to other CO limits PR 1109.1 in addition to those in Tables 1 and 2

Paragraph (d)(7) requires that a carbon monoxide (CO) emission limit established in a SCAQMD Permit to Operate (PTO) for a Unit continue to meet that PTO limit instead of the CO emission limit *"... specified in Table 1 or Table 2."* SCAQMD has established CO limits in other provisions of PR 1109.1 besides those listed in Table 1 and Table 2 that should also be subject to the overlap provision in paragraph (d)(7). Where these CO limits are generally drawn from Table 1 or Table 2 but are not directly referenced, this may lead to confusion on applicability of the CO limit if paragraph (d)(7) does not specify whether the CO limit in a PTO or PR 1109.1 applies. See subparagraphs (d)(3)(A) through (C) and (d)(4)(A) through (C) for CO limits that do not refer directly to Table 1 or Table 2 and thus are not currently covered by the (d)(7) overlap. Also, the interim CO limits in paragraph (f)(1) in Table 4 should be subject to paragraph (d)(7). 7-6

MPC recommends broadening the language in paragraph (d)(7) to clarify that CO emission limits in an applicable PTO limit shall continue to be met in lieu of those in PR 1109.1. See Attachment 1 for proposed revisions to paragraph (d)(7).

Additionally, in regard to CO limits in PR 1109.1, MPC notes the following proposed corrections:

- Paragraph (e)(2) for a B-Cap includes the phrase *"... that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits..."*. Under PR 1109.1, a B-Cap is for NOx only and is not also for CO. The term "and CO" must be removed from paragraph (e)(2). This change would make the language consistent with that in paragraph (e)(1) for a B-Plan that does not contain the "and CO" term.

- Paragraph (j)(3) refers to CO emission limits in Table 3. Table 3 does not have CO limits but Table 4 does, so paragraph (j)(3) should instead reference Table 4.

6. Compliance schedule requirements in paragraphs (d)(8) and (d)(9) for Table 1 or Table 2 limits should be incorporated into subdivision (g) (Compliance Schedule) and remove potential conflicts.

Paragraph (d)(8) establishes a schedule to demonstrate compliance with applicable limits in Table 1 or Table 2 that are less than a 365-day averaging period. The schedule is to demonstrate compliance with these limits *"... six months after, either the date the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued or completion of a compliance demonstration source test, whichever is sooner."* However, clauses (g)(1)(B)(i) and (ii) specify different compliance schedules for Table 1 limits, as follows: *"(i) No later than 36 months after a South Coast AQMD Permit to Construct is issued; or (ii) No later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A)."* These two schedules conflict and will lead to confusion as to when compliance needs to be demonstrated for Table 1 limits. MPC recommends incorporating paragraphs (d)(8) and (d)(9) as well as other compliance schedule requirements in subdivisions (d) and (e), as applicable, into subdivision (g) titled "Compliance Schedule," such that all compliance schedule requirements are located in one rule subdivision. 7-7

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Relatedly, it is unclear when a permit application is required or is not required under subparagraph (g)(1)(B)(ii). Generally, a permit application will be needed to incorporate the Table 1 limit, but it is unclear when a permit application is not required. MPC requests regulatory clarification on this issue.

Paragraph (d)(9) establishes a compliance schedule for limits with a 365-day rolling average, but this paragraph does not state which limits this schedule applies to. Although MPC presumes this paragraph is intended to address limits in Table 1 or Table 2, as with paragraph (d)(8), SCAQMD needs to clearly state this. Otherwise, this paragraph could be misconstrued as establishing a compliance schedule for a B-Plan or B-Cap, which have 365-day rolling average limits, instead of the schedule specified in paragraph (g)(2) that explicitly addresses the compliance schedule requirements for a B-Plan or B-Cap. See Attachment 1 for proposed revisions to paragraph (d)(9). 7-7 (cont'd)

7. PR 1109.1 sets an inappropriate early shutdown deadline for permanently decommissioned units under the B-Cap.

Clause (e)(2)(D)(i), excerpted below, requires that a Unit scheduled to be permanently decommissioned as part of an approved B-Cap surrender the SCAQMD PTO by specified dates.

> *(i) Surrender the South Coast AQMD Permit to Operate no later than the compliance date for Phase I in I-Plan Option 4 and no later than the permit submittal date for all other phases in an approved I-Plan; ...*

This clause specifies that the "compliance date" for Phase I in I-Plan Option 4 is the permit surrender deadline, but SCAQMD uses a term "permit submittal date" as the deadline for the other I-Plan phases. It is unclear whether "permit submittal date" is referring to a permit application by the Facility, a permit issued by SCAQMD, or some other permit-related action. MPC believes that the permit surrender deadline should not be at any time before the compliance date in Table 6 for all of the I-Plan options in order to provide sufficient time to complete projects that may be important to allow for decommissioning of a Unit prior to the compliance date for an I-Plan phase. MPC recommends simply referring to the listed compliance dates in Table 6. See Attachment 1 for proposed revisions to clause (e)(2)(D)(i). 7-8

Related to this issue, no description exists in PR 1109.1 or the Draft Staff Report for the process to "surrender" a permit. MPC requests additional clarification on the process to surrender or inactivate a PTO for a permanently decommissioned unit.

Finally, clause (e)(2)(D)(iii) reads as if a Unit cannot be sold to a company that is located within the South Coast Air Basin instead of reflecting the intent that the Unit cannot be operated in the South Coast Air Basin. See Attachment 1 for proposed revisions to clause (e)(2)(D)(iii) to reflect this intent.

8. A BARCT B-Cap fully realizes the emission reduction objectives of PR 1109.1, and demonstration with a B-Cap's BARCT Emission Targets is met by monitoring and reporting of the Facility's actual emissions.

The B-Cap is an alternative compliance option provided for under PR 1109.1 that can also achieve the NOx emission reductions. As SCAQMD notes in its August 2021 Preliminary Draft Report for PR 1109.1 and Proposed Rescinded Rule 1109 (Draft Staff Report), *"The B-Cap achieves the same emission reductions as if the facility complied directly with the proposed NOx limits."*[12] MPC supports the 7-9

[12] SCAQMD, "Preliminary Draft Staff Report, Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page Ex-1.

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SCAQMD inclusion of the B-Cap option in paragraph (e)(2) of PR 1109.1 to provide an alternative means of demonstrating equivalent cumulative NOx emissions reductions such that the facility may achieve these emissions reductions in a safer and more cost-effective way. However, SCAQMD includes an additional demonstration in the Implementation Compliance Plan (I-Plan) that requires the facility to show that the planned NOx emissions reduction projects in concert with any other strategies to reduce mass emissions will, prospectively, meet the applicable Emission Target. This additional prospective demonstration is summarized as follows:

1. Select an Alternative BARCT NOx Limit on a concentration basis for every unit, which for heaters and boilers must be on a 24-hour rolling average, per subparagraph (e)(2)(B) of the rule. This value cannot exceed the Maximum Alternative BARCT NOx Limits for a B-Cap in Table 3.

2. Accept a permit limit for the Alternative BARCT NOx Limit for every unit, per subparagraph (e)(2)(C) of the rule.

3. Calculate the Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions (B-Cap Annual Emissions) by requiring, in part, the use of the Alternative BARCT NOx Limit per subparagraph (g)(2)(F) and following the calculation method in Attachment B of the rule at Subsection B-6.1. 7-9 (cont'd)

4. Demonstrate in an Implementation Compliance Plan (I-Plan) and B-Cap submittal that the prospective B-Cap Annual Emissions, which incorporates and uses the Alternative BARCT NOx Limit for each unit and other strategies to reduce mass emissions, will not exceed the Emission Targets per subparagraph (g)(2)(G) and by the phased schedule for the chosen I-Plan option. The I-Plan is an additional requirement of the facility that elects to meet a B-Cap. The I-Plan is *"designed to maximize early emissions reductions, where feasible"* to meet each phase of the mass emission targets by deadlines established in Table 6 of PR 1109.1.[13]

The requirement to institute a unit-specific concentration limit such as an Alternative BARCT NOx Limit may be appropriate for the BARCT Equivalent Compliance Plan (B-Plan), which is a separate compliance option from the B-Cap that is based on establishing alternative NOx concentration limits. Conversely, a B-Cap is based on annual mass emissions from the units, which is a function of both the annual average NOx concentration and firing rates of each unit. Instituting a 24-hour average maximum NOx concentration for heaters and other units has no direct coupling to actual sustained emissions, since the 24-hour restricted maximum concentration is based on established worst-case conditions (highest design NOx concentration) that may occur over the course of the normal operating envelope of the emissions unit and control device. MPC's February 1, 2021 comment letter provides details on the inherent variability in NOx concentrations at a heater as well as variable firing rates that materially affect sustained actual emissions. Using a 24-hour maximum concentration to calculate an annual emissions rate for every unit will, by itself, result in a vastly unrealistic overestimate of the facility's future emissions.

For this reason, the Alternative BARCT NOx Limit should not be used solely to calculate the B-Cap Annual Emissions as other variables are important to calculate emissions. The calculation method for the facility's B-Cap Annual Emissions in Attachment B at Subsection B-6.1, excerpted below, allows the incorporation of "emissions reductions from reduced throughput, efficiency, reduced capacity, and any

[13] SCAQMD, "Preliminary Draft Staff Report, Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page Ex-1

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other strategy to reduce mass emissions." A facility should not be penalized for operating at NOx concentration levels that are lower than the 24-hour Alternative BARCT NOx Limit at its heaters and other units when it is able to practically do so and when operating conditions allow. This and other related strategies to reduce annual NOx emissions is an important and necessary element of the B-Cap Annual Emissions calculation that would be considered in the "(Throughput or Other Reductions)" aspect of the equation.

$$\text{Phase I BARCT B} - \text{Cap Annual Emissions}_{B-Cap} = \sum_{i=1}^{N}\left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})$$

Where:

N = Number of included units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Cap for unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions as defined in subdivision (c) and for unit i included in the B-Cap

Throughput or Other Reductions = Emission reductions occurred from other than reducing the concentration limit.

For planning purposes in the B-Cap submittal, an appropriate and representative calculation of B-Cap Annual Emissions is based on the firing rate and concentration of each unit that incorporates emissions reductions projects and other strategies to reduce mass emissions. This basic demonstration of future emissions scenario(s) is not the means for which compliance with the Emission Targets is ultimately met, but rather it serves as a means of SCAQMD reviewing and approving the B-Cap and I-Plan for implementation. Compliance with the B-Cap as a practical matter is a matter of the facility showing that its actual NOx emissions are less than the applicable Emission Targets. MPC requests that the SCAQMD document their agreement that the "(Throughput or Other Reductions)" aspect of the equation above can include a variety of different means to achieve the Emission Targets, including operating at lower annual-average emissions levels. 7-9 (cont'd)

9. The 24-hour rolling average associated with PR 1109.1 NOx concentration limits for boilers and process heaters is not reasonable as it is not representative of inherent operational variability associated these units.

Maximum NOx concentration limits are established in PR 1109.1 for boilers and process heaters on a 24-hour rolling average. These limits and the associated short-term averaging period are not proven and/or are infeasible for some refinery heaters. Burner manufacturers generally base their NOx emissions specifications and guarantees on set operating conditions, including combustion air temperature, fuel gas composition, and excess air going to the burner(s). Refineries have dynamic operating conditions and it is 7-10

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common for process heaters to run at a wide operating envelope that deviate from the ideal set of conditions that are used for burner NOx concentration specifications.

Over a longer averaging period like a 365-day rolling average, the heater's operating conditions may more closely align with those presumed by the burner manufacturer in establishing the NOx emissions guarantee, but a 24-hour rolling average limit may not always be met when there are hydrogen and other compositional and heating value fluctuations in refinery fuel gas, changes in oxygen content within the heater, or other real-world variabilities in operating conditions that can cause the NOx concentration to increase above the limit in the short-term. MPC proposes that the averaging period for NOx concentration limits at boilers and process heaters be changed from 24-hour rolling average to 365-day rolling average. 7-10 (cont'd)

10. SCAQMD's approval process for an I-Plan, B-Plan, and B-Cap should be granted to the Facility if the information described in paragraph (i)(4) is provided.

Paragraph (i)(4) and its references to paragraphs (i)(1) through (3) contain the prescriptive informational elements for the Facility to provide in an I-Plan, B-Plan, or B-Cap to be approved by SCAQMD. Paragraph (i)(4) provides for SCAQMD to approve or disapprove the I-Plan, B-Plan, or B-Cap based on whether the owner or operator demonstrates that certain requirements have been met. In general, the information required in these plans are prescriptive in nature, consisting of data and calculations, such that SCAQMD should not disapprove a Plan submittal if it contains this information. However, per subparagraph (i)(4)(C), the Facility gets only one opportunity to correct any deficiencies and re-submit a Plan, and then if SCAQMD disapproves the Plan, the Facility must comply with the schedule in paragraph (g)(1) which excludes the alternative compliance demonstration of a B-Plan or B-Cap. This mandatory and stringent off-ramp from a B-Plan or B-Cap to instead meet the Table 1 limits is unworkable to a Facility that has made long-term plans to meet one of these alternative compliance methods. MPC proposes changes to paragraph (i)(4) in Attachment 1 of this letter that: 7-11

- Provides SCAQMD 30 days to conduct an initial administrative completeness review of the Plan(s);
- Clarifies SCAQMD shall not disapprove a Plan if the Facility provides the required information in the rule;
- Removes the mandatory off-ramp for a Facility to meet the compliance schedule in paragraph (g)(1) instead of (g)(2); and
- Subjects an I-Plan, B-Plan, or B-Cap to Rule 221 – Plans.

MPC has also included in Attachment 1 of this letter proposed corrections and updates to subdivision (i) to address other updates, as summarized below:

- New subparagraphs (i)(1)(A), (i)(2)(A), and (i)(3)(A) are introduced to clarify if multiple Facilities are covered in a single I-Plan, B-Plan, and B-Cap due to being under the same ownership.
- Subparagraphs (i)(1) and (i)(3) should reference the BARCT Equivalent Mass Emissions Cap for the B-Cap instead of the Alternative NOx BARCT Limit for a B-Plan as the key approach to address equivalent emissions reductions under PR 1109.1.

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- Subparagraph (i)(1)(D) is duplicative of subparagraph (i)(1)(F) and should be removed.
- Subparagraph (i)(1)(F) references the wrong citation for specification of the I-Plan option, so this reference has been updated.
- Subparagraph (i)(3)(D), shown as subparagraph (i)(3)(E) in Attachment 1 of this letter, restricts reductions in mass emissions to those only associated with a reduction in throughput, but Attachment B at Section B-6 allows for other reductions to be incorporated into the BARCT Annual Emissions calculation. The language in this subparagraph is updated to be consistent with Section B-6. 7-11 (cont'd)
- Subparagraph (i)(3)(E), shown as subparagraph (i)(3)(F) in Attachment 1 of this letter, incorrectly references the term "BARCT Equivalent Mass Emissions" for a B-Plan instead of the term "BARCT B-Cap Annual Emissions" for a B-Cap.
- Subparagraph (i)(4)(B), shown as subparagraph (i)(4)(D) in Attachment 1 of this letter, allows only 30 days for a Facility to correct deficiencies and resubmit a Plan. MPC requests the more reasonable 60 days instead of 30 days in the event that the deficiencies noted by SCAQMD require additional time to develop new information and prepare a resubmittal.
- Clause (i)(5)(C)(iv) requires a modification to the Plan if an emission reduction project is moved to a different implementation phase or is removed from a phase. The compulsory information required in subparagraph (i)(1) through (4) does not include the time frame for emission reduction projects, so it should not be a criterion for requiring a modification to the Plan. The permitting process is a more appropriate means of addressing changes that involve emission reduction projects.

11. The interim limit for a B-Cap in paragraph (f)(3) requires additional specificity on the compliance time frame.

Paragraph (f)(3), excerpted below, establishes a requirement to maintain emissions in aggregate below the Baseline Facility Emissions.

> *"(3) An owner or operator of a Former RECLAIM Facility that elects to comply with an approved B-Cap shall not operate any unit included in the approved B-Cap unless the NOx emissions for all units in the B-Cap are in aggregate at or below the Baseline Facility Emission."* 7-12

MPC requests that SCAQMD clarify the compliance demonstration elements of this rule provision, specifically to: (1) identify the compliance date (also see item 6 regarding compliance dates), (2) stipulate the averaging period (i.e., 365-day rolling average), and (3) clarify when the interim limit is no longer applicable.

12. Certain provisions for time extension requests in subdivision (h) should be adjusted to support timely approvals.

7-13

Time extensions for an approved I-Plan may be requested per paragraph (h)(2) under certain listed criteria. MPC requests the following changes that will allow for an improved process to qualify for and be granted time extensions:

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- Clause (h)(2)(C)(i) allows an owner or operator to apply for a time extension if it took 24 months for SCAQMD to issue a permit after submittal of a permit application. MPC requests that this time frame be changed from 24 to 18 months to provide a more reasonable permitting time frame for projects needed to meet PR 1109.1.

- Paragraph (h)(4) allows SCAQMD 60 days to act on a time extension request. MPC requests that this time frame be changed to 30 days in order to provide sufficient time for an owner or operator to respond to any deficiencies noted by SCAQMD in a Plan submittal before a compliance deadline. 7-13 (cont'd)

- Paragraph (h)(7) lists two deadlines for a Facility to meet emission limits if a time extension is disapproved. MPC proposes to add the phrase "whichever is later" at the end to provide certainty on the applicable deadline.

13. Key averaging time and testing schedule requirements in the emissions testing provisions need to be revised.

MPC offers the following proposed changes to address concerns with the testing provisions in subdivision (k).

- MPC proposes a new subparagraph to address the potential conflict between the source test requirements in Tables 7 and 8 of PR 1109.1 and those in a SCAQMD PTO. See Attachment 1 for new paragraph (k)(3).

- The source test protocol for paragraph (k)(7) requires *"an averaging time of at least 2 hours."* The Draft Staff Report at page 3-23 states that the averaging time is *"no less than 15 minutes but no longer than 2 hours."* MPC proposes to change the language in subparagraphs (k)(7)(A) and (B) to that shown as subparagraphs (k)(8)(A) and (B) in Attachment 1 of this letter, which reflects the draft staff report. 7-14

- The timing in subparagraph (k)(7)(A) to submit a source test protocol relative to receiving a Permit to Construct may not be possible, because the Facility may not have sufficient detailed information for a complete protocol if the Unit is still being designed. Similarly, the timing in subparagraph (k)(7)(C) to conduct a source test within 90 days upon approval of the source test protocol may not be possible, because the air pollution control equipment may not be installed and fully operational by that time. To address this, MPC proposes that the source test protocol timing is a function of the source test itself in order to ensure that the unit is operational (e.g., that it has resumed stable operations after completion of an emission reduction project) and is ready for testing. See Attachment 1 for revisions to subparagraphs (k)(7)(A) and (B) which are shown as subparagraphs (k)(8)(A) and (B) in Attachment 1 of this letter.

- MPC proposes to change the deadline for submitting a source test report in paragraph (k)(11) from 60 to 90 days of completion of the source test. Due to the increased number of source testing obligations pursuant to PR 1109.1 and the fact that meeting this requirement is primarily a function of the contracted and SCAQMD-approved source testing firm, an additional 30 days is needed to address the increased workload and potential delays in reporting by a source testing firm.

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14. The provision to limit the total amount of NOx emission reductions from decommissioned units to 15% under a B-Cap new unit exemption is unreasonably low.

Subparagraph (e)(2)(F) contains restrictions on adding a new unit under the B-Cap. Of particular concern is clause (e)(2)(F)(iv) that restricts the total amount of NOx reductions from decommissioned units to 15 percent of the Final Phase Facility BARCT Emission Target. From the Draft Staff Report, it appears that this clause is attempting to address SCAQMD's concerns with a unit being replaced with a "functionally similar unit outside the B-Cap".[14] To address this concern, MPC proposes to revise the clause to address units that are decommissioned but not replaced with a functionally similar Unit. Accordingly, this will appropriately delineate between projects that are being completed to satisfy environmental rule obligations and unit replacements. With this restriction in place, MPC believes that the 15% threshold should be higher and it should be based on the Total Facility NOx Emissions Reductions, and not the Final Phase BARCT Emission Target, which compares emission reductions for decommissioned units to total reductions. See Attachment 1 for a proposed revision to clause (e)(2)(F)(iv). 7-15

Relatedly, MPC notes that clause (e)(2)(F)(i) refers to *"Equivalent Mass Emission"* instead of *"B-Cap Annual Emissions."* The former term is for a B-Plan and is not applicable to a B-Cap. MPC has updated this clause in Attachment 1 of this letter.

15. The future established NOx limits for small refinery boilers and heaters is not based on BARCT.

SCAQMD includes 5 ppmv and 9 ppmv NOx limits for small refinery boilers and heaters, respectively, at subparagraphs (d)(3)(C) and (d)(4)(C), that take effect in the future. These limits are not based on a current technology that is safe, technically feasible, and cost-effective, which are compulsory elements of a control technology to be considered for BARCT. Instead, SCAQMD states that the limits are based on emerging technologies and that staff *"... will monitor the development of emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized."*[15] It is practically impossible to know if a technology will be technically feasible, safe to operate, and cost-effective for small refinery boilers and heaters ten years from now or even further into the future. By establishing such limits in this rulemaking, it goes against the Health & Safety Code that requires technical feasibility and cost effectiveness be demonstrated in order for a control technology to be BARCT. 7-16

MPC believes these future limits that are not based on BARCT should be removed from the rule. At the least, MPC recommends that SCAQMD make the future effective date of these limits dependent on the results of SCAQMD's status report in 2029 that addresses whether or not these emerging technologies are technically feasible and cost-effective for BARCT as of 2029 or later.

16. Potential confusion between the RECLAIM transition and B-Cap related limits and associated calculation and monitoring methods needs to be addressed in the rule.

MPC requests clarity as to when a Facility is operating after the effective date of PR 1109.1 but before it becomes a Former RECLAIM Petroleum Refinery. Specifically, PR 429.1 addresses startup and shutdown emissions for PR 1109.1 but only applies to a Former RECLAIM Petroleum Refinery. Until a 7-17

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[14] SCAQMD, "Preliminary Draft Staff Report: Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page 3-10

[15] SCAQMD, "Preliminary Draft Staff Report: Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page 3-6

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Final Determination Notification is issued, it is unclear how a Facility is to address applicable limits that may be in effect for PR 1109.1. Relatedly, compliance with Rules 218.2 and 218.3 for CEMS is not required until a Facility becomes a Former RECLAIM Petroleum Refinery. For any limits in effect under PR 1109.1 at the Facility until it receives a Final Determination Notification, it is unclear if the Facility should follow a different set of CEMS requirements. MPC requests regulatory certainty to address the transition between RECLAIM and PR 1109.1 for compliance monitoring. 7-17 (cont'd)

17. PR 1109.1 contains other clerical and administrative errors that need to be corrected.

Attachment 1 is a mark-up of PR 1109.1 with proposed changes as described in this letter and as follows:

- The rolling average times in Table 3 that are shown as "24-day" should be "24-hour."
- Capitalize words such as "Unit," "Petroleum Refinery," "Facility," etc., consistently throughout the rule to refer to the term defined in subdivision (c).
- Add in missing words for correct syntax. 7-18

Note that Attachment 1 of this letter is a conversion of the Adobe PDF version of PR 1109.1 into Microsoft Word, so the formatting of Attachment 1 is not as exact as shown in the August 20, 2021 version on SCAQMD's website.

For additional clarity, MPC recommends that SCAQMD add rule definitions for acronyms and shortened terms used in the rule such as "BARCT," "RECLAIM," and "O_2." MPC has not included proposed definitions for these terms in Attachment 1.

18. PR 1109.1 needs to reference and incorporate the startup and shutdown provisions in PR 429.1 and revise PR 429.1 so as to appropriately address management of startups and shutdowns.

The proposed PR 1109.1 rule does not reference PR 429.1 or otherwise clarify how startup and shutdown emissions are to be included or excluded for accounting against emission limits. Particularly, PR 1109.1 needs to expressly state that emissions from startups and shutdowns are exempt when determining compliance with the Alternative NOx BARCT Limits and the annual mass emissions against the BARCT Emissions Targets. To remove this ambiguity, MPC requests SCAQMD add a reference or statement in PR 1109.1 excluding the emissions from startup and shutdown events in PR 429.1 for purposes of compliance with emission limits in PR 1109.1. 7-19

Regarding the proposed PR 429.1 rule itself, MPC offers the following comments to address multiple startup and shutdown activities that are required for compliance with PR 1109.1. Attachment 2 of this letter is a proposed mark-up of PR 429.1 to reflect MPC's comments.

A. <u>Cogeneration unit electrical testing</u>

Cogeneration units are subject to industry and electrical standards to ensure that the equipment is reliable and in good working order. This includes conducting electrical testing following any upgrades or repairs made to the cogeneration unit's safety and control systems (e.g., protection relay and excitation control systems). These tests are to ensure that the systems have been functionally tested to prevent process safety and reliability issues. Some testing must take place at different electrical loads that can only occur during the startup phase. The testing duration ranges from 4 to 12 hours depending on the complexity of the 7-20

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testing. As this testing is to ensure the safety and reliability of the system, MPC requests that this testing be categorically excluded from the time limitations in paragraph (d)(2) of PR 429.1 by including the following: 7-20 (cont'd)

- Add the following exemption as a new subparagraph (g)(1)(E) to paragraph (g)(1): *"electrical testing associated with commissioning of cogeneration control systems following upgrades or repairs."*; and

- Copy the definition of gas turbine from subdivision (c) of PR 1109.1, which incorporates the term "cogeneration."

B. Catalyst maintenance and related activities

MPC offers the following proposed changes to address catalyst maintenance and related activities:

- Paragraph (c)(2) requires that catalyst maintenance for a Unit *"... which has a bypass stack or duct ..."* MPC requests removal of this phrase, since some combustion units have only one stack which is used for both normal operations and for catalyst maintenance activities that bypass the control equipment (i.e., the control equipment is not operable during control equipment maintenance). Paragraph (d)(8) is also revised to align with this definition.

- The proposed definition in paragraph (c)(2) is specific only to catalyst maintenance activities and is not inclusive of other maintenance activities inherently needed for NOx post-combustion control equipment. For example, routine maintenance activities associated with a post-combustion control equipment's ammonia injection system and related components is required, which would impact emissions because ammonia is not being introduced into the control equipment during that time. MPC proposes to revise this definition to include maintenance of ancillary components in NOx post-combustion control equipment. 7-21

- Paragraph (d)(7) is an operating requirement for post-combustion control equipment if the temperature of the exhaust gas to the inlet of the control equipment *"... is greater than or equal to the minimum operating temperature."* Operating temperature fluctuates during startup, and MPC has observed from its operations that the minimum temperature may be initially reached for a very short duration and then fall below that minimum temperature before again rising to a minimum temperature until the stabilized minimum temperature is reached. For this reason, MPC requests that the aforementioned phrase be changed to *"... is greater than or equal to the minimum operating <u>and stable</u> temperature."*

- Subparagraph (d)(8)(D) requires documentation from a manufacturer of the *"minimum safe operating rate for the unit being bypassed."* The minimum safe operating rate for a Unit is a function of process safety management reviews by operations and safety staff and the application of MPC's operational safety policies and procedures to a Unit. Manufacturers will not know or have documentation of the minimum safe operating rate for a Unit. MPC requests deletion of this subparagraph.

C. Gas turbines with NOx post-combustion control equipment

Gas turbines with NOx post-combustion control equipment have issues that are similar to boilers and process heaters with respect to the necessary time allowance to meet NOx emission limits. MPC requests 7-22

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that Table 1 of PR 429.1 be changed such that a gas turbine with NOx post-combustion control equipment is subject to the same 48-hour time allowance as boiler and process heaters with NOx post-combustion control equipment. 7-22 (cont'd)

D. Two-hour duration limit in Table 1 for process heaters

Based upon a review of its procedures and practices, MPC has determined that the startup and shutdown duration limit of two hours in Table 1 is insufficient for process heaters. It is unclear in the corresponding Draft Staff Report how this hourly limit was established. From MPC's experience it is unrealistic for several process heaters that do not have post-combustion NOx control equipment to reach stable conditions in two hours such that the NOx emissions controls (i.e., ultra-low NOx burners) can effectively meet the emission limits in PR 1109.1. For example, some heaters inherently require slower warming to avoid damaging downstream equipment affected by temperature changes and thus need more than 2 hours to start up. Also, heaters with natural draft systems or several dozen burners that need to be lit during startup will make control of excess oxygen difficult at low and fluctuating firing rates, which causes higher NOx concentrations until stable conditions are reached. To ensure MPC is allotted sufficient time to allow for safe and steady startup, MPC requests additional consultation with SCAQMD to support an appropriate increase to the 2-hour duration limit currently proposed in Table 1 for process heaters. 7-23

19. PR 1304 should further clarify in the rule language that BACT exemption is allowed for equipment replacements across categories of equipment.

MPC appreciates SCAQMD's consideration for including a limited exemption from BACT requirements for PM_{10} and SO_X emissions from projects that are implemented to comply with the PR 1109.1 requirements. This is important for allowing projects that will be completed for PR 1109.1 compliance to be permitted efficiently and implemented in a cost-effective manner. While the language in PR 1304(f)(1)(B) appears to allow for the exemption to apply to equipment to be replaced with other equipment across different source categories, there are some references in the associated PR 1304 Draft Staff Report indicating that equipment can only be replaced within the same source category (e.g., boilers replacing boilers).[16] For projects that involve replacement of equipment across source categories (e.g., boilers replacing co-generation units) that is functionally similar and does not increase the cumulative total maximum rated capacity, the rule language and staff report should be updated to reflect that the limited BACT exemption in PR 1304(f)(1) can be used. MPC has provided suggested rule language changes in Attachment 1 of this letter. 7-24

20. PR 1304 (f)(1)(B) should allow for a longer period for replaced equipment to be operated at the same time consistent with federal requirements

Subparagraph (f)(1)(B) of PR 1304 currently states that *"For the new and/or modified permit unit(s) and the permit unit(s) being replaced, a maximum of 90 days is allowed as a startup period for simultaneous operation."* The length of time allowed for simultaneous operation of replacement units should be adjusted to align with the requirements of 40 CFR § 51.165(a)(1)(vi)(F) which allows a 180-day transition period for replacement units. This is a more appropriate time period when units are being replaced. PR 1304(f)(1)(B) should be adjusted to align with 40 CFR § 51.165(a)(1)(vi)(F). 7-25

[16] SCAQMD, "Preliminary Draft Staff Report, Proposed Amended 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM" http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/pdsr-par-1304_2005-aug-2021.pdf?sfvrsn=16 page 2-2

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Conclusion

MPC provides these comments to the Preliminary Draft Proposed Rule 1109.1 and related proposed and proposed amended rules issued August 20, 2021 to address critical deficiencies and needed clarifications. 7-26

Please note that in submitting this letter, MPC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the Proposed Rule 1109.1 rulemaking process.

Thank you for the opportunity to provide comments. We are glad to discuss further and look forward to continued dialogue.

Sincerely,

Bradley J. Levi

Brad Levi
Vice President – Los Angeles Refinery

Attachments

cc: ***SCAQMD***
Sarah Rees – Deputy Executive Officer
Susan Nakamura – Assistant Deputy Executive Officer
Michael Krause – Planning and Rules Manager

cc: ***SCAQMD Governing Board***
Hon. Ben Benoit – Governing Board Chair
Hon. Lisa Bartlett – Governing Board Member
Hon. Joe Buscaino – Governing Board Member
Hon. Michael Cacciotti – Governing Board Member
Hon. Vanessa Delgado – Governing Board Vice-Chair
Hon. Gideon Kracov – Governing Board Member
Hon. Sheila Kuehl – Governing Board Member
Hon. Larry McCallon – Governing Board Member
Hon. Veronica Padilla-Campos – Governing Board Member
Hon. V. Manuel Perez – Governing Board Member
Hon. Rex Richardson – Governing Board Member
Hon. Carlos Rodriguez – Governing Board Member
Hon. Janice Rutherford – Governing Board Member

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ecc: 2021-09-17 MPC 75 Day Comment Letter on Revised Draft of SCAQMD PR 1109.1
Ruth Cade, MPC RE
Chris Drechsel, MPC RE
Denis Kurt, MPC LAR
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Attachment 1

Proposed changes to PR 1109.1 (August 20, 2021 version)

Preliminary Draft Rule

(Adopted TBD)
Revision Date 8-20-21

PROPOSED RULE 1109.1. EMISSIONS OF OXIDES OF NITROGEN FROM PETROLEUM REFINERIES AND RELATED OPERATIONS

(a) Purpose

The purpose of this rule is to reduce emissions of oxides of nitrogen (NOx), while not increasing carbon monoxide (CO) emissions, from ~~units~~Units at ~~petroleum refineries~~a Petroleum Refineries and ~~facilities~~Facilities with ~~related operations~~Related Operations to ~~petroleum refineries~~Petroleum Refineries.

(b) Applicability

The provisions of this rule shall apply to an owner or operator of ~~units~~Units at ~~petroleum refineries~~Petroleum Refineries and ~~facilities~~Facilities with ~~related operations~~Related Operations to ~~petroleum refineries~~Petroleum Refineries.

(c) Definitions

(1) ALTERNATIVE BARCT NOx LIMIT FOR PHASE I, PHASE II, ~~OR~~AND PHASE III means the ~~unit~~Unit specific NOx concentration limit that is selected by the owner or operator of a Facility to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target in the aggregate in the B-Plan or B-Cap, where the NOx concentration limit will include the corresponding percent O_2 correction and determined based on the averaging time in Table 1 or subdivision (k), whichever is applicable. ~~subdivision (k), whichever is applicable.~~

(2) ASPHALT PLANT means a ~~facility~~Facility that processes crude oil into asphalt.

(3) BASELINE FACILITY EMISSIONS means the sum of all the Baseline Unit Emissions at a Facility as calculated according to Attachment B of this rule.

(4) BASELINE UNIT EMISSIONS means a Unit's emissions as reported in the 2017 NOx Annual Emissions Report, or another representative year, as approved by the Executive Officer.

(5) BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator to select NOx concentration limits for all Units subject to this rule that are equivalent, in aggregate, to the NOx concentration limits specified in Table 1 and Table 2.

(6) BARCT EQUIVALENT MASS CAP PLAN (B-CAP) means a compliance

Preliminary Draft Rule

plan that establishes a mass emission cap for all ~~units~~Units subject to this rule

PR 1109.1 - 2

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

that, in aggregate, are equivalent to or less than the Final Phase Facility BARCT Emission Target.

(7) BIOFUEL PLANT means a Facility that produces fuel by processing feedstocks including vegetable oil, animal fats, and tallow.

(8) BOILER means any Unit that is fired with gaseous fuel and used to produce steam. For the purpose of this rule, boiler does not include CO boilers.

(9) CO BOILER means a boiler with an integral waste heat recovery system used to oxidize CO-rich waste gases generated by the FCCU.

(10) COMPLIANCE DATE means the date at which the Facility shall begin to quantify emissions as required by this rule. The first period for compliance with an applicable emissions limit occurs after the date following the compliance date and the averaging period of the limit.

~~(10)~~(11) CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) is as defined by Rule 218 – Continuous Emission Monitoring.

~~(11)~~(12) DUCT BURNER means a device in the heat recovery steam generator of a Gas Turbine that combusts fuel and adds heat energy to the gas turbine exhaust.

~~(12)~~(13) FACILITIES WITH RELATED OPERATIONS TO PETROLEUM REFINERIES includes Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, ~~petroleum coke calcining facilities~~Petroleum Coke Calcining Facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants.

~~(13)~~(14) FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

~~(14)~~(15) FACILITY or FACILITIES means, for the purpose of this rule, any ~~unit~~Unit or group of ~~units~~Units which are located on one or more contiguous properties, in actual physical contact or separated solely by a public roadway or other public right-of--way, and operate under one South Coast AQMD Facility ID or Facilities with the Same Ownership.

~~(15)~~(16) FINAL DETERMINATION NOTIFICATION means the notification issued by the Executive Officer to a RECLAIM ~~facility~~Facility designating that the ~~facility~~Facility is no longer in the NOx RECLAIM program.

~~(16)~~(17) FINAL PHASE FACILITY BARCT EMISSION TARGET means the total mass emissions remaining per Facility calculated based on the applicable Table 1 emission limits or Table 2 conditional emission limits and the Baseline Facility Emissions.

~~(17)~~(18) FLARE means, for the purpose of this rule, a combustion device that

PR 1109.1 - 2

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

oxidizes combustible gases or vapors from tank farms or liquid unloading, where the combustible gases or vapors being destroyed are routed directly

PR 1109.1 - 3

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

into the burner without energy recovery, and that is not subject to Rule 1118 – Control of Emissions from Refinery Flares.

~~(18)~~(19) FLUIDIZED CATALYTIC CRACKING UNIT (FCCU) means a Unit in which petroleum intermediate feedstock is charged and fractured into smaller molecules in the presence of a catalyst; or reacts with a contact material to improve feedstock quality for additional processing; and the catalyst or contact material is regenerated by burning off coke and other deposits. The FCCU includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat including a CO boiler.

~~(19)~~(20) FORMER RECLAIM FACILITY means a Facility, ~~or any of~~including its successors, that was in the NOx Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a Final Determination Notification, and is no longer in the NOx RECLAIM program.

~~(20)~~(21) FUNCTIONALLY SIMILAR means, for the purpose of this rule, a Unit that will perform the same purpose as a Unit that was permanently decommissioned in an approved B-Cap.

~~(21)~~(22) GAS TURBINE means an internal-combustion engine in which the expanding combustion gases drive a turbine which then drives a generator to produce electricity. Gas Turbines can be equipped with a cogeneration gas turbine that recovers heat from the Gas Turbine exhaust and can include a Duct Burner.

~~(22)~~(23) HEAT INPUT means the heat of combustion released by burning a fuel source, using the Higher Heating Value of the fuel. This does not include the enthalpy of incoming combustion air.

~~(23)~~(24) HIGHER HEATING VALUE (HHV) means the total heat liberated per mass of fuel combusted expressed as British thermal ~~units~~Units (Btu) per pound or cubic feet when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to their standard states at standard conditions.

~~(24)~~(25) HYDROGEN PRODUCTION PLANT means a Facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes which primarily supplies hydrogen for petroleum refineries and Facilities with Related Operations to Petroleum Refineries.

PR 1109.1 - 4

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(25)~~(26) IMPLEMENTATION COMPLIANCE PLAN (I-PLAN) means an implementation plan for Facilities with six or more Units that includes an alternative implementation schedule and alternative emission reduction targets.

~~(26)~~(27) I-PLAN PERCENT REDUCTION TARGET means the percent reduction target specified for each phase of an I-Plan as specified in Table 6.

~~(27)~~(28) NATURAL GAS means a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

~~(28)~~(29) NEW UNIT means, for the purpose of this rule, any Unit that meets the applicability of subdivision (b) where the South Coast AQMD Permit to Construct is issued on or after [*DATE OF ADOPTION*].

~~(29)~~(30) OXIDES OF NITROGEN (NOx) EMISSIONS means the sum of nitric oxide and nitrogen dioxide emitted in the flue gas, calculated, and expressed as nitrogen dioxide.

~~(30)~~(31) PARTS PER MILLION BY VOLUME (ppmv) means, for the purpose of this rule, milligram of pollutant per liter of dry combustion exhaust gas at standard conditions.

~~(31)~~(32) PETROLEUM COKE CALCINER means a Unit used to drive off contaminants from green petroleum coke by bringing the coke into contact with heated gas for the purpose of thermal processing. The Petroleum Coke Calciner includes, but is not limited to, a kiln, which is a refractory lined cylindrical device that rotates on its own axis, and a pyroscrubber, which combusts large carbon particles in a stream of waste gas.

~~(32)~~(33) PETROLEUM COKE CALCINING FACILITY means a Unit within a Petroleum Refinery, or as a separate Facility, that operates a ~~petroleum coke calciner~~Petroleum Coke Calciner.

~~(33)~~(34) PETROLEUM REFINERY means a Facility identified by the North American Industry Classification System Code 324110, Petroleum Refineries.

~~(34)~~(35) PHASE I, PHASE III, OR PHASE III BARCT B-CAP ANNUAL EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III, permanently decommissioned ~~units~~Units, and other emission reduction strategies to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission

PR 1109.1 - 5

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

~~(35)~~(36) PHASE I, PHASE II, OR PHASE III BARCT EQUIVALENT MASS EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates respective BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

~~(36)~~(37) PHASE I, PHASE II, OR PHASE III FACILITY BARCT EMISSION TARGET means the total NOx mass emissions per Facility that must be achieved in an approved B-Plan or B-Cap that are based on the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan option in Table 6 and are calculated pursuant to Attachment B of this rule.

~~(37)~~(38) PROCESS HEATER means any Unit fired with gaseous and/or liquid fuels which transfers heat from combusted gases to water or process streams.

~~(38)~~(39) RATED HEAT INPUT CAPACITY means the maximum heat input capacity, which is the total heat of combustion released by burning a fuel source, as specified by the South Coast AQMD permit.

~~(39)~~(40) REPRESENTATIVE NOx CONCENTRATION means the most representative NOx emissions in the exhaust of the Unit as approved by the Executive Officer and measured by a certified CEMS if the Unit operates with a certified CEMS or the most recent approved source test for ~~units~~Units not operating a certified CEMS. The Representative NOx Concentration for ~~units~~Units that do not have CEMS or source test emission data will be based on the South Coast AQMD Annual Emission Report default emission factor for that Units.

~~(40)~~(41) RULE 1109.1 EMISSION LIMITS mean the NOx and CO emission limits and corresponding percent O_2 correction listed in paragraphs (d)(3),(d)(4), Table 1, Table 2, Table 4, Table 5, an approved B-Plan, or an approved B-Cap.

~~(41)~~(42) STANDARD CONDITIONS for a Former RECLAIM Facility is as defined by Rule 102 – Definition of Terms .

~~(42)~~(43) STEAM METHANE REFORMER (SMR) HEATER means any Unit that is fired with gaseous fuels and transfers heat from the combusted fuel to process tubes that contain catalyst, which converts light hydrocarbons combined with steam to hydrogen.

PR 1109.1 - 6

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(43)~~(44) SULFURIC ACID FURNACE means a Unit fueled with gaseous fuels and/or hydrogen sulfide gas used to convert elemental sulfur and/or decompose spent sulfuric acid, into sulfur dioxide (SO_2) gas.

~~(44)~~(45) SULFURIC ACID PLANT means a Unit within a Petroleum Refinery, or as a separate Facility, engaged in the production of commercial grades of sulfuric acid, or regeneration of spent sulfuric acid into commercial grades of sulfuric acid.

~~(45)~~(46) SULFUR RECOVERY PLANT means a Unit within a Petroleum Refinery, or as a separate Facility, that recovers elemental sulfur or sulfur compounds from sour or acid gases and/or sour water generated by Petroleum Refineries.

~~(46)~~(47) SULFUR RECOVERY UNITS/TAIL GAS (SRU/TG) INCINERATORS means the thermal or catalytic oxidizer where the residual hydrogen sulfide in the gas exiting the sulfur recovery plant (tail gas) is oxidized to SO_2 before being emitted to the atmosphere.

~~(47)~~(48) UNIT means, for the purpose of this rule, any ~~boilers, flares, FCCUs, gas turbines, petroleum coke calciners, process heaters~~Boiler, Flare, FCCU, Gas Turbine, Petroleum Coke Calciner, Process Heater, SMR ~~heaters, sulfuric acid furnaces~~Heater, Sulfuric Acid Furnace, SRU/TG ~~incinerators~~Incinerator, or ~~vapor incinerators~~Vapor Incinerator requiring a South Coast AQMD ~~permit~~Permit and not required to comply with another NOx emission limit in a South Coast AQMD Regulation XI rule.

~~(48)~~(49) UNIT REDUCTION means the potential NOx emission reduction for a Unit if the Unit's NOx emissions were reduced from the Representative NOx Concentration to the applicable NOx concentration limit in Table 1 based on the Baseline Emissions calculated pursuant to Attachment B of this rule.

~~(49)~~(50) UNITS WITH COMBINED STACKS means two or more Units where the flue gas from these Units are combined in one or more common stack(s).

~~(50)~~(51) VAPOR INCINERATOR means a thermal oxidizer, afterburner, or other device for burning and destroying air toxics, volatile organic compounds, or other combustible vapors in gas or aerosol form in gas streams.

(d) Emission Limits

(1) An owner or operator shall not operate a ~~unit~~Unit that exceeds the applicable NOx and CO emission limits at the percent O_2 correction specified in Table 1 and the averaging time specified in Table 1 or subdivision (k), whichever is applicable pursuant to the compliance

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

schedule in
subdivision (g).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 1: NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to paragraph (d)(3)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to paragraph (d)(4)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

1 Averaging times apply to ~~units~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Conditional NOx and CO Emission Limits

(A) An owner or operator of a ~~unit~~Unit is eligible to meet the NOx and CO emission limits in Table 2, in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a post combustion control device for the ~~unit~~Unit;

(ii) For a ~~process heater~~Process Heater with a ~~rated heat input capacity~~Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour and less than 110 MMBtu/hour or less, the Unit Reduction calculated pursuant ~~to~~ Attachment B of this rule is less than 10 tons per year based on the applicable Table 1 NOx emission limit;

(iii) For boilers or process heaters with a Rated Heat Input Capacity greater than 110 MMBtu/hour, the Unit Reduction calculated pursuant to Attachment B of this rule is less than 20 tons per year based on the applicable Table 1 NOx emission limit;

(iv) The South Coast AQMD Permit to Construct or South Coast AQMD Permit to Operate for the ~~unit~~Unit does not have a condition that limits the NOx concentration to a level at or below the applicable Table 1 NOx emission limit;

(v) The Representative NOx Concentration of the ~~unit~~Unit is not below the applicable Table 1 NOx emission limit; and

(vi) The ~~unit~~Unit is not identified as being permanently decommissioned in an approved B-Plan for reductions in an I-Plan or approved B-—Cap pursuant to subparagraph (e)(1)(D) or (e)(2)(D).

(B) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emission limits in Table 2 in lieu of the NOx and CO emission limits in Table 1 shall:

(i) Before July 1, 2022, submit a complete South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2; and

(ii) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

at the percent O_2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(C) Notwithstanding subparagraph (d)(2)(A) and (d)(2)(B), an owner or operator shall meet the Conditional NOx and CO Emission Limits in Table 2 in lieu of the NOx and CO Emission Limits in Table 1 if:

(i) The owner or operator is submitting a B-Plan or a B-Cap, and their ~~unit~~Unit is listed in Table D-1;

(ii) The owner or operator is submitting a B-Cap and has selected I-Plan Option 4, and their ~~unit~~Unit is listed in Table D-2.

TABLE 2: CONDITIONAL NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters 40 – ~~10~~110 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	24-hour

[1] Averaging times apply to ~~units~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

(3) Boilers with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a boiler with a rated heat input capacity less than 40 MMBtu/hour shall:

(A) Before January 1, 2023, have a South Coast AQMD Permit that includes an enforceable emission limit that does not exceed 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction and limits the

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averaging times to Table 1 or subdivision (k), whichever is applicable.

(B) On and after January 1, 2023, not operate a boiler that exceeds 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction as demonstrated pursuant to the averaging times in Table 1 or subdivision (k), whichever is applicable; and

(C) No later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a boiler or replaces burners that represent 50 percent or more of the heat input in a boiler, where the cumulative replacement begins from July 1, 2022, shall:

(i) Submit a complete South Coast AQMD permit application to impose a 5 ppmv NOx emission limit and a 400 ppmv CO emission limit at three percent O_2 correction that limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and

(ii) Meet the emission limits pursuant to clause (d)(3)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour–

~~(4)~~ An owner or operator of a process heater with a rated heat input capacity less than 40 MMBtu/hour shall:

(A) Before January 1, 2023, have a South Coast AQMD Permit that includes an enforceable emission limit that does not exceed 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable;

(B) On and after January 1, 2023, not operate a process heater that exceeds 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction as demonstrated pursuant to the averaging times in Table 1 or subdivision (k), whichever is applicable; and

(C) Effective [*TEN YEARS AFTER DATE OF ADOPTION*], no later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a process heater or replaces burners that represent 50 percent or more of the heat input

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

in a process heater, where the cumulative replacement begins from [*FIVE YEARS AFTER DATE OF ADOPTION*], shall:

~~(i)~~ Submit a complete South Coast AQMD permit application to impose a ~~9ppmv~~9 ppmv NOx emission limit and a 400 ppmv CO

(i) emission limit at three percent O_2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and

~~applicable; and~~

(ii) Meet the emission limits pursuant to clause (d)(4)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(5) Gas Turbines

Notwithstanding the NOx emission limits in Table 1, an owner or operator shall not operate a gas turbine that exceeds 5 ppmv NOx corrected to 15 percent O_2 ~~correction~~ based on a 24-hour rolling average during natural gas curtailment periods, where there is a shortage in the supply of pipeline natural gas due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas, provided:

(A) A daily gas turbine operating record is maintained that includes the actual start and stop time, total hours of operation, and type (liquid or gas) and quantity of fuel used; and

(B) This information is available to South Coast AQMD staff upon request for at least five years from the date of entry.

(6) An owner or operator of ~~units~~Units with ~~combined stacks~~Combined Stacks shall be subject to the most stringent applicable Table 1 or Table 2 NOx and CO emission limit at the percent O2 correction based on the averaging time in Table 1 or subdivision (k), whichever is applicable.

(7) An owner or operator of a ~~unit~~Unit with a CO emission limit in a South Coast AQMD Permit to Operate that was established before [DATE OF ADOPTION], shall meet the CO emission limit in the South Coast AQMD Permit to Operate in lieu of the CO emission limit specified in ~~Table 1 or Table 2.~~subdivisions (d) through (f).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(8) An owner or operator of a ~~unit~~Unit with an averaging time less than 365-day in Table 1 or Table 2 that operates a CEMS shall be required to demonstrate compliance with the applicable NOx emission limits in Table 1, Table 2, an approved B-Plan, or an approved B-Cap six months after~~,~~ ~~either~~ the date the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

(9) An owner or operator of a ~~unit~~Unit subject to a 365-day rolling average in Table 1 or Table 2 shall demonstrate compliance with the Rule 1109.1 Emission Limits beginning 14 months after either the date the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

(e) B-Plan and B-Cap Requirements

(1) An owner or operator of a ~~facility~~Facility with six or more ~~units~~Units that elects to meet the NOx emission limits in an approved B-Plan in lieu of meeting Table 1 or Table 2 NOx emission limits shall:

(A) Before July 1, 2022, submit ~~an~~a South Coast AQMPD Permit to Construct application for a B-Plan that includes all ~~units~~Units subject to this rule, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and Phase III to meet the respective Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed:

(i) The Conditional NOx and CO limit in Table 2, for any ~~unit~~Unit that is meeting a Conditional NOx and CO Emission Limit pursuant to subparagraphs (d)(2)(A) and (d)(2)(B).

(C) Comply with a condition in the South Coast AQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit Phase I, Phase II, and if applicable Phase III for each ~~unit~~Unit in the approved B- Plan based on the schedule

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

established in the approved I-Plan;

(D) Not include ~~emission reductions~~Emission Reductions for any ~~unit~~Unit that is permanently decommissioned; and

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(E) Not operate a ~~unit~~Unit that exceeds the Alternative BARCT NOx Limit, CO emission limit, based on the averaging time in Table 1 or ~~the~~ subdivision (k), whichever is applicable, in an approved B-Plan, based on the implementation schedule in the approved I-Plan.

(2) An owner or operator of a ~~facility~~Facility with six or more ~~units~~Units that elects to meet the NOx ~~and CO~~ emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall:

(A) Before July 1, 2022, submit a B-Cap and an I-Plan to the Executive Officer that ~~includes~~include all ~~units~~Units subject to this rule, with the exception of any ~~boiler~~Boiler or ~~process heater~~Process Heater with a Rated Heat Heat Input Capacity less than 40 MMBtu/hour, that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last ~~Compliance Date~~compliance date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and Phase III to meet the respective Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed;

(i) The Maximum Alternative BARCT NOx Limit for the applicable ~~unit~~Unit, specified in Table 3; and

(ii) The Conditional NOx ~~and CO~~ limit in Table 2, for any ~~unit~~Unit that is meeting a Conditional NOx ~~and CO Emission Limit~~limit pursuant to subparagraphs (d)(2)(A) or (d)(2)(B).

(C) Comply with a condition in the South Coast AQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III for each ~~unit~~Unit in the approved B-Cap based on the schedule established in the approved I-Plan;

(D) For any ~~unit~~Unit that is permanently decommissioned, represent the permanently decommissioned ~~unit~~Unit as Table 1 NOx emissions in the Phase I, Phase II, or Phase III Facility BARCT Emission Target in an approved B-Cap, and for the ~~unit~~Unit that is permanently decommissioned the owner or operator shall:

(i) Surrender the South Coast AQMD Permit to Operate no later than the compliance date ~~for~~ in Table 6 corresponding to

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Phase I ~~in I-Plan Option 4 and no later than~~ , Phase II, or Phase III as specified in the ~~permit submittal date for all other phases in an~~ approved I-Plan for permanently decommissioning the Unit;

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(ii) Disconnect and blind the fuel line(s) on or before the South Coast AQMD Permit to Operate is surrendered pursuant to clause (e)(2)(D)(i); and

(iii) Not sell the ~~unit for operation~~ Unit to another entity for operation within the South Coast Air Basin;

(E) Not operate any ~~unit~~Unit unless the NOx emissions for all ~~units~~Units in the approved B-Cap are in aggregate at or below the applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, based on the schedule in the approved I-Plan; and

(F) Not add a new ~~unit~~Unit that will be subject to this rule that increases the ~~facility~~Facility emissions above applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, unless:

(i) All ~~units~~Units in the approved B-Cap meet the ~~Equivalent Mass Emission~~B-Cap Annual Emissions;

(ii) The new ~~unit~~Unit is not functionally similar to any ~~unit~~Unit that was permanently decommissioned in the approved B-Cap;

(iii) The new ~~unit~~Unit will not increase overall ~~facility~~Facility throughput; and

(iv) The total amount of NOx emission reductions from ~~units~~Units that were permanently decommissioned and not replaced with functionally similar Units, represents ~~15~~40 percent or less of ~~Final Phase Facility BARCT Emission Target~~Total Facility NOx Emission Reduction in an approved B-~~-~~Cap.

TABLE 3: MAXIMUM ALTERNATIVE BARCT NOX LIMITS FOR A B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-~~day~~hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-~~day~~hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

			~~day~~hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SRU/TG Incinerators	100 ppmv	3	24-~~day~~hour
Vapor Incinerators	40 ppmv	3	24-~~day~~hour

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

[1] Averaging times apply to ~~units~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

(f) Interim Emission Limits

(1) An owner or operator of a ~~facility~~Facility that elects to comply with the emission limits in Table 1, Table 2, or an approved B-Plan shall not operate a ~~unit~~Unit that exceeds the applicable interim NOx and CO emission limits based on the measured O_2 correction and the averaging time in Table 4 or subdivision (k), whichever is applicable, until that ~~unit~~Unit is required to meet another Rule 1109.1 Emission Limit pursuant to the compliance schedule in paragraph (g)(1) or an approved I-Plan.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 4: INTERIM NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraph (f)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciners	85	2,000	3	365-day
SMR Heaters	20[2]	400	3	365-day
	60[3]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	105	400	3	365-day

[1] Averaging times are applicable to ~~units~~Units with a CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

[2] SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [*DATE OF ADOPTION*].

[3] SMR Heaters not equipped with post-combustion air pollution control equipment as of [*DATE OF ADOPTION*].

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Interim NOx emission limits for Boilers and Process Heaters
An owner or operator of a Former RECLAIM Facility shall:

(A) Not exceed the applicable interim NOx emission rate in Table 5, calculated pursuant to Attachment A Section (A-2) of this rule, for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour and boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate with a NOx CEMS.

TABLE 5: INTERIM NOX EMISSION RATES FOR BOILERS AND PROCESS HEATERS ≥40 MMBTU/HOUR

Units	An Owner or Operator that Elects to Comply with an Approved:	Facility NOx Emission Rate (pounds/million Btu)	Rolling Averaging Time
Boilers and Process Heaters: ≥40 MMBtu/Hour and <40 MMBtu/hour Operating a Certified CEMS	B-Plan using I-Plan Option 3	0.02	365-day
	B-Plan	0.03	365-day

(B) Demonstrate compliance with the applicable interim NOx emission rate in Table 5 until all boilers and process heaters subject to paragraph (f)(2) meet the NOx concentration limits in Table 1, Table 2, or an approved B-Plan.

(3) An owner or operator of a Former RECLAIM Facility that elects to comply with an approved B-Cap shall not operate any ~~unit~~Unit included in the approved B-Cap unless the NOx emissions for all ~~units~~Units in the B-Cap are in aggregate at or below the Baseline Facility ~~Emission~~Emissions.

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(g) Compliance Schedule

(1) An owner or operator of a ~~unit~~Unit that is required to meet the NOx and CO concentration limits specified in Table 1 shall:

(A) Before July 1, 2023, submit a complete South Coast AQMD permit application to establish a permit condition that limits the NOx concentration based on the percent O_2 correction and the averaging time in Table 1 or subdivision (k), whichever is applicable, unless the owner or operator has a South Coast AQMD Permit to Construct or a South Coast AQMD Permit to Operate with the NOx concentration limit at the percent O_2 correction, based on the averaging time specified in Table 1; and

~~(B)~~ Not operate a ~~unit~~Unit, that exceeds the NOx and CO emission limits

(B) based on the percent O_2 correction and the averaging time in Table 1 or subdivision (k), whichever is applicable:

(i) No later than 36 months after a South Coast AQMD Permit to Construct is issued; or

(ii) No later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A).

(2) I-Plan Requirements

An owner or operator with six or more ~~units~~Units that elects to meet the NOx and CO emission limits using an alternative compliance schedule to paragraph (g)(1) or that elects to comply with an approved B-Plan or B-Cap shall:

(A) Before July 1, 2022, submit an I-Plan pursuant to paragraph (i)(1) that includes all ~~units~~Units subject to Table 1 NOx emission limits for review and approval pursuant to paragraph (i)(4), with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

~~(B) Calculate the Phase I, Phase II, or Phase III Facility BARCT Emission Targets, pursuant to Attachment B of this rule;~~

~~(C) For a B-Cap, the Phase I, Phase II, and Phase III Facility BARCT Emission Targets shall incorporate a reduction of 10 percent, pursuant to Attachment B of this rule;~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(D) For a B-Plan, calculate the Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions, pursuant to Attachment B of this rule;~~

~~(E) For a B-Plan, demonstrate that Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions, are equal to or less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target;~~

~~(F) For a B-Cap, calculate the Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions, pursuant to Attachment B of this rule;~~

~~(G) For a B-Cap, demonstrate that Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions, are equal to or less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target;~~

~~(H)~~(B) Based on the schedule in the approved I-Plan, implement emission reduction projects to comply with the emission limits in Table 1 or Table 2 or an approved B-Plan or approved B-Cap, to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target; and

~~(I)~~(C) For an owner or operator with an approved B-Cap, demonstrate compliance with the emissions requirements and all other requirements no later than the compliance date for Phase I in I-Plan Option 4 and no later ~~54 months from South Coast AQMD Permit Application Submittal Date~~than the compliance date in Table 6 for all other phases of the selected I--Plan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 6: I-PLAN PERCENT REDUCTION TARGETS AND ~~SCHEDULE~~[1]SCHEDULE

		Phase I	Phase II	Phase III
I-Plan Option 1 for B-Plan Only	Percent Reduction Targets	70	100	N/A
	Permit Application Submittal Date	July 1, 2023	January 1, 2027	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 2 for B-Plan Only	Percent Reduction Targets	60	80	100
	Permit Application Submittal Date	July 1, 2023	January 1, 2025	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		
I-Plan Option 3 for B-Plan or B-Cap and as allowed pursuant to paragraph (g)(3)	Percent Reduction Targets	50	100	N/A
	Permit Application Submittal Date	January 1, 2025	January 1, 2029	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 4 for B-Cap Only	Percent Reduction Targets	50 to 60 (Still in development)	80	100
	Permit Application Submittal Date	N/A	January 1, 2025	January 1, 2028
	Compliance Date	January 1, 2024	No later than 36 months after a South Coast AQMD Permit to Construct is issued	
I-Plan Option 5 for B-Cap Only	Percent Reduction Targets	50	70	100
	Permit Application Submittal Date	July 1, 2022	July 1, 2024	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(3) I-Plan Option 3 is only available to an owner or operator of a ~~facility~~Facility achieving a NOx emission rate of less than 0.02 pound per million BTU of heat input, based on annual emissions for the applicable ~~units~~Units as reported in the 2021 Annual Emissions Report and calculated pursuant to Attachment A, for all the boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour based on the maximum rated capacity by [*DATE OF ADOPTION*]; for ~~units~~Units firing at less than the maximum rated capacity, mass emissions shall be less than or equal to the quantity that would occur at maximum rated capacity.

(4) An owner or operator of a ~~unit~~Unit complying with Table 2 conditional emission limits that replaces existing NOx control equipment shall:

(A) Within six months of replacing the existing NOx control equipment, be subject to the applicable Table 1 emission limit;

(B) Apply for a South Coast AQMD permit condition to limit the NOx and CO concentration to the applicable Table 1 emission limit at the corresponding percent O_2 correction and averaging times in Table 1 or subdivision (k), whichever is applicable. Replacement of existing NOx control equipment will be determined as:

(i) Existing post-combustion air pollution control equipment for an FCCU, gas turbine fueled with natural gas, process heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour, or SMR Heater is replaced such that the fixed capital cost of the new components for the post-combustion air pollution control equipment exceeds 50 percent of the fixed capital cost that would be required to construct and install a comparable new ~~unit~~Unit; or

(ii) 50 percent or more of the burners in a vapor incinerator, or 50 percent or more of the rated heat input capacity of the burners in a vapor incinerator, are cumulatively replaced after [*DATE OF ADOPTION*].

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~~(5)~~ An owner or operator of ~~unit complying with clauses (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A) that fails to submit a complete South Coast AQMD permit application by the date specified in causes (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A), shall meet the applicable Rule 1109.1 Emission Limits no later than 36 months after the South Coast AQMD permit application submittal date pursuant to causes (d)(2)(B)(i), (d)(3)(C)(i), or (d)(4)(C)(i), or subparagraphs (g)(1)(A) or (g)(5)(A).~~

~~(6)~~(5) ~~An owner or operator of a unit~~a Unit exempt from the Table 1 NOx and CO emission limits pursuant to paragraphs (n)(2), (n)(3), (n)(6), (n)(7), (n)(8) or (n)(9) that exceeds the applicable exemptions limitations shall:

(A) Within six months of the exceedance, submit a complete South Coast AQMD permit application to comply with the corresponding Table 1 emission limit; and

(B) Meet the emission limits specified on Table 1 no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(h) Time Extensions

(1) An owner or operator of a ~~unit~~Unit may request one 12-~~-~~month extension for each ~~unit~~Unit from the compliance date in paragraph (g)(1) or the Compliance Date in Table 6 provided:

(A) The South Coast AQMD permit application for the ~~unit~~Unit was submitted on or before the date specified in paragraph (g)(1) or the approved I-Plan; and

(B) There are specific circumstances outside of the control of the owner or operator that necessitate an extension of time.

(2) An owner or operator of a ~~unit~~Unit with an approved I-Plan may request a time extension from the Compliance Date in Table 6 for a ~~unit~~Unit provided:

(A) The South Coast AQMD permit application for the ~~unit~~Unit was submitted on or before the date specified in the approved I-Plan;

(B) The month and year for the ~~unit's~~Unit's scheduled turnaround and the month and year for the ~~unit's~~Unit's subsequent turnaround is submitted in writing at the time of South Coast AQMD permit application submittal; and

(C) One or more of the following occurred:

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(i) The South Coast AQMD Permit to Construct for the ~~unit~~Unit was issued after the scheduled turnaround date or the South Coast AQMD Permit to Construct for the ~~unit~~Unit was issued more than ~~24~~18 months after the South Coast AQMD permit application was submitted, and either:

(ii) The subsequent scheduled turnaround for the ~~unit~~Unit will not occur until 12 months after the Compliance Date in the approved I-Plan; or

(iii) The subsequent scheduled turnaround for the ~~unit~~Unit will occur more than 48 months after the South Coast AQMD Permit to Construct was issued.

(3) An owner or operator that requests a time extension pursuant to paragraphs (h)(1) or (h)(2) shall submit the request in writing to the Executive Officer no later than 90 days prior to the Compliance Date in paragraph (g)(1) or the approved I-Plan for the ~~unit~~Unit. The time extension request shall include:

(A) The phase and ~~unit~~Unit needing a time extension;

(B) The date the South Coast AQMD permit application was submitted;

(C) The additional time needed to complete the emission reduction project;

(D) Specify if the time extension request is for paragraph (h)(1) or (h)(2);

(E) For time extension requests for paragraph (h)(2), provide the month and year of the scheduled turnaround, and the subsequent turnaround, if applicable, for the ~~unit~~Unit; and

(F) The reason(s) a time extension is requested.

(4) The Executive Officer will review the request for the time extension and act on the request within ~~60~~30 days of receipt provided an owner or operator:

(A) Meets the requirements of paragraph (h)(1) or (h)(2), as applicable;

(B) Submitted the written request within the timeframe and includes the applicable information specified in paragraphs (h)(1) and (h)(2); and

(C) For a time extension request pursuant to paragraphs (h)(1) and (h)(2), the owner or operator shall at a minimum:

(i) For delays due to missed milestones, provide information on schedules and/or construction plans documenting the key milestones and which key milestone(s) were delayed with an

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

explanation actions the operator took to ensure milestones were met and why the delay necessitates additional time;

(ii) For delays related to other agency approvals, provide information to substantiate that the submittal of information to the agency was timely, the date when application was the approval was requested, and documentation from the agency of reason for the delay;

(iii) For delays related to the delivery of parts or equipment, provide purchase orders, invoices, and communications from vendors that demonstrate that equipment was ordered in a timely fashion and delays are outside of the control of the operator; and

(iv) For delays related to contract workers, source testers, installers, or other services, provide an explanation of the service, when the service was requested, the response time, and information to substantiate why the delay necessitates additional time.

(D) For a time extension request allowed under paragraphs (h)(2), the owner or operator shall provide documentation to substantiate that one of the provisions under subparagraph (h)(2)(C) have been met.

(5) If the Executive Officer requests additional information to substantiate the time extension request, the owner or operator shall provide that information within the timeframe specified by the Executive Officer.

(6) If the Executive Officer notifies the owner or operator of approval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within timeframe in the approval, and the approval represents an amendment to the I-Plan.

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(7) If the Executive Officer notifies the owner or operator of a disapproval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within 60 calendar days after receiving notification of disapproval of the time extension request or pursuant to the compliance schedule in paragraph (g)(1) or the schedule in an approved I-Plan, whichever is later.

(i) I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

(1) I-Plan Submittal Requirements

An owner or operator that elects to implement an I-Plan pursuant to paragraph (g)(2) to meet the Alternative BARCT NOx Limits in an approved B-Plan ~~or~~, or the BARCT Equivalent Mass Emission Cap in an approved B-Cap shall submit an I-Plan to the Executive Officer for review and approval that:

(A) Identifies all Facilities by Facility identification number under same ownership subject to the rule that are included in the I-Plan;

~~(A)~~(B) Identifies each ~~unit~~Unit subject to the rule by device identification number with a description of each ~~unit~~Unit, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meetthe NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

~~(B)~~(C) For ~~facilities~~Facilities to use the time extension pursuant to paragraph (h)(2), identifies the anticipated start and end date (month and year) of the turnaround schedule for each ~~unit~~Unit;

~~(C)~~(D) Specifies either I-Plan Option 1 (for a B-Plan only), I-Plan Option (for a B-Plan only) 2, I-Plan Option 3 (for a B-Plan or B-Cap), I--Plan Option 4 (for a B-Cap only), or I-Plan Option 5 (for a B-Cap only) in Table 6;

~~(D) Calculates the Phase I, Phase II, or Phase III Facility BARCT Emission Target, pursuant to Attachment B of this rule;~~

(E) For a B-Plan, identifies each ~~unit~~Unit that meets the requirements under subparagraph (d)(2)(A) for use of a conditional NOx emission limit in Table 2 and the owner or operator submitted a complete South Coast AQMD permit application pursuant to clause (d)(2)(B)(i);

(F) For the selected I-Plan option specified pursuant to subparagraph

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(i)(1)(~~B~~D), calculates the Phase I, Phase II, or Phase III Facility BARCT Emission Target, pursuant to Attachment B of this rule; and

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(G) Identifies each ~~unit~~Unit by device identification number with a description of each ~~unit~~Unit, that cumulatively meets Phase I, Phase II, or Phase III Facility BARCT Emission Target.

(2) B-Plan Submittal Requirements

An owner or operator that elects to meet Alternative BARCT NOx Limits in an approved B-Plan pursuant to paragraph (e)(1), shall submit a B-Plan to the Executive Officer for review that:

(A) Identifies all Facilities by Facility identification number under same ownership subject to the rule that are included in the B-Plan;

~~(A)~~(B) Identifies for each ~~unit~~Unit subject to the rule by device identification number with a description of each ~~unit~~Unit, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

~~(B)~~(C) Specifies the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III of the approved I-Plan;

~~(C)~~(D) Calculates the Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions using the Alternative BARCT NOx Limits ~~identified in subparagraph (g)(2)(B)~~, as calculated pursuant to Attachment B of this rule; and

~~(D)~~(E) Demonstrates that Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions are less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target.

(3) B-Cap Submittal Requirements

An owner or operator that elects to meet the ~~Alternative~~ BARCT ~~NOx Limits~~Equivalent Mass Emission Cap in an approved B-Cap pursuant to paragraph (e)(2), shall submit a B-Cap to the Executive Officer for review that:

(A) Identifies all Facilities by Facility identification number under same ownership subject to the rule that are included in the B-Cap;

~~(A)~~(B) Identifies each ~~unit~~Unit subject to the rule by the device identification number with a description of the ~~unit~~Unit, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, and:

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(B)~~(C) Specifies the Alternative BARCT NOx Limit that is at or below Maximum Alternative BARCT NOx Limit in Table 3;

~~(C)~~(D) Identifies any ~~unit~~Unit that will be permanently decommissioned for each phase of the approved I-Plan;

~~(D)~~(E) Identifies any ~~unit~~Unit that will have ~~a reduction~~other reductions in ~~throughput~~mass emissions for each phase of the approved I-Plan;

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(E)~~(F) Calculates the Phase I, Phase II, or Phase III BARCT ~~Equivalent Mass~~B-Cap Annual Emissions using ~~the~~ emission reduction strategies ~~identified in subparagraph (g)(3)(B)~~; as calculated pursuant to Attachment B of this rule; and

(G) Demonstrates that Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions, are less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target ~~that incorporates a 10 percent reduction pursuant to subparagraph (g)(2)(C);~~.

~~(F)~~(H) Demonstrates that the B-Cap and I-Plan submittal satisfies the environmental benefit definition in U.S. EPA's January 2001 guidance document entitled "Improving Air Quality With Economic Incentive Programs."

(4) I-Plan, B-Plan, and B-Cap Review and Approval Process

(A) Within 30 days of receipt, the Executive Officer will conduct an initial review of the applicable plan(s) and request any additional information that was not provided in subparagraph (i)(4)(B).

~~(A)~~(B) The Executive Officer will notify the owner or operator in writing whether the I-Plan, B-Plan, or B-Cap is approved or disapproved based on the following criteria:

(i) The I-Plan contains information required in paragraph (i)(1), the B-Plan contains information required in paragraph (i)(2), and the B-Cap contains information required in paragraph (i)(3);

(ii) The owner or operator demonstrates that the requirements of subparagraphs (d)(2)(A) and (d)(2)(B) have been met for any ~~unit~~Unit not listed in Attachment D-2 that is meeting a Table 2 conditional NOx emission limit, in lieu of a Table 1 NOx emission limit;

(iii) For a B-Plan, the Phase I, Phase II, or Phase III Equivalent BARCT Emissions are less than or equal to the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target ~~as required in subparagraph (g)(2)(B)~~;

(iv) For a B-Cap, the Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions are less than or equal to the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target ~~that incorporates a 10 percent reductions pursuant to subparagraph (g)(2)(C)~~;

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(v) For a B-Cap, the NOx concentration limit for any ~~unit~~Unit does not exceed the Maximum Alternative BARCT NOx Limits in Table 3.

(C) The Executive Officer shall not disapprove the I-Plan, B-Plan, or B-Cap or a modification to these Plan(s) if the Facility provides the information required in (i)(4)(B).

~~(B)~~(D) Within ~~30~~60 days of receiving written notification from Executive Officer that the I-Plan, B-Plan, or B-Cap is ~~disapproved~~deficient, the owner or operator shall correct any deficiencies and re-submit the I-Plan, B-Plan, or B-Cap.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(C) Upon receiving written notification from the Executive Officer that the I-Plan, B-Plan, or B-Cap re-submitted pursuant to subparagraph (i)(4)(B) is disapproved, the owner or operator shall comply with the compliance schedule pursuant to paragraph (g)(1).~~

(E) An I-Plan, B-Plan or B-Cap shall be subject to Rule 221 – Plans.

(5) Modifications to an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap

(A) An owner or operator that seeks approval to modify an approved I-Plan, an approved B-Plan, or an approved B-Cap shall submit a request in writing to the Executive Officer to modify an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap.

(B) The modification request submitted pursuant to subparagraph (i)(5)(A) shall include all the plan submittal requirements pursuant to paragraph (i)(1) for an approved I-Plan, paragraph (i)(2) for a modification of an approved B-Plan, or paragraph (i)(3) for a modification of an approved B-Plan;

(C) An owner or operator shall modify an approved I-Plan, B-Plan, or B-Cap if:

(i) A ~~unit~~Unit identified as meeting Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (d)(2)(B);

(ii) A ~~unit~~Unit in an approved B-Cap or B-Plan, identified as meeting Table 2 for establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is permanently decommissioned;

(iii) A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that ~~unit~~Unit in the currently approved I-Plan, B-Plan, or B-Cap; or

~~(iv) Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase; or~~

~~(v)~~(iv) The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed.

(D) Review and approval of any modifications to an I-Plan, B-Plan, or

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

B-Cap shall conducted in accordance with the review and approval process pursuant to paragraph (i)(4).

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(6) Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap
The Executive Officer will make the I-Plan, B-Plan, or B-Cap or modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval.

(7) Plan Fees
The review and approval of an I-Plan, B-Plan, and B-Cap, or review and approval of a modification of an approved I-Plan, B-Plan, and B-Cap shall be subject to applicable plan fees as specified in Rule 306 – Plan Fees.

(j) CEMS Requirements

(1) An owner or operator of a Former RECLAIM Facility with a ~~unit~~Unit with a rated heat input capacity of greater than or equal to 40 MMBtu/hour shall install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements to demonstrate compliance with NOx emission limits at the corresponding percent O_2 correction and averaging times.

(2) An owner or operator of a Former RECLAIM Facility with a sulfuric acid furnace subject to the emission limits in Table 1, Table 4, an approved B-Plan or an approved B-Cap shall:

(i) Install, certify, operate, and maintain a CEMS to measure NOx pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Rule 1109.1 Emissions Limits; and

(ii) Within 12 months from [*DATE OF ADOPTION*] shall install, certify, operate, and maintain a CEMS that complies with the Rules 218.2 and 218.3 requirements to measure O_2 and demonstrate compliance with the Rule 1109.1 Emission Limits at the corresponding percent O_2 correction.

(3) An owner or operator of a ~~unit~~Unit with a CEMS that measures CO at [*DATE OF ADOPTION*] must operate and maintain the CO CEMS pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Table 1, Table 2, or Table ~~3~~4 CO emissions limits and certify the CEMS within 12 months of [*DATE OF ADOPTION*] pursuant to the applicable Rules 218.2 and 218.3 requirements.

(4) An owner or operator of a Former RECLAIM Facility for a ~~unit~~Unit with a CEMS shall exclude invalid CEMS data pursuant to Rule 218.2 –

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications.

(5) Missing Data Procedures for a Facility Complying with a B-Cap

An owner or operator of a ~~unit~~Unit with an approved B-Cap with a non-operational CEMS that is not collecting data, shall:

(A) Calculate missing data using the average of the recorded emissions for the hour immediately before the missing data period and the hour immediately after the missing data period, if the missing data period is less than or equal to 8 continuous hours; or

(B) Calculate missing data using the maximum hourly emissions recorded for the previous 30 days, commencing on the day immediately prior to the day the missing data occurred, if the missing data period is more than 8 continuous hours.

(k) Source Test Requirements

(1) An owner or operator of a ~~unit~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) shall be required to conduct a source test, with a duration of at least 15 minutes but no longer than two hours, to demonstrate compliance with Rule 1109.1 Emission Limits pursuant to the source test schedule in either Table 7 or Table 8.

(2) Source Test Schedule for Units without Ammonia Emissions in the Exhaust

An owner or operator of a ~~unit~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) and does not vent to post-combustion air pollution control equipment with ammonia injection, shall demonstrate compliance with the applicable Rule 1109.1 Emission Limits by conducting source tests according to the schedule in Table 7.

(3) An owner or operator of a Unit with source testing requirements in a South Coast AQMD Permit to Operate for NOx or CO shall follow the applicable source test requirements in the South Coast AQMD Permit to Operate in lieu of the source test requirements in Table 7 and Table 8.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 7: SOURCE TESTING SCHEDULE
FOR UNITS WITHOUT AMMONIA EMISSIONS IN THE EXHAUST

Combustion Equipment	Source Test Schedule
Vapor Incinerators less than 40MMBtu/hr, Flares	• Conduct source test simultaneously for NOx and CO within 36 months from previous source test and every 36 months thereafter
All Other Units	
Units Operating without NOx or CO CEMS	• Conduct source test simultaneously for NOx and CO within 12 months of being subject to Rule 1109.1 Emission Limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO emission limits prior to resuming annual source tests
Units operating with NOx CEMS and without CO CEMS	• Conduct source test for CO within 12 months from previous source test and every 12 months thereafter
Units operating without NOx CEMS and with CO CEMS	• Conduct source test for NOx during the first 12 months of being subject to Rule 1109.1 Emission Limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx emissions limits prior to resuming annual source tests

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(3)~~(4) Source Test Schedule for Units with Ammonia Emissions in the Exhaust
An owner or operator of a ~~unit~~Unit with post-combustion air pollution control equipment that requires ammonia injection shall demonstrate compliance with the applicable Rule 1109.1 Emission Limit and ammonia South Coast AQMD permit limit by conducting a source test according to the schedule in Table 8.

TABLE 8: SOURCE TESTING SCHEDULE FOR UNITS WITH AMMONIA EMISSIONS IN THE EXHAUST

Combustion Equipment	Source Test Schedule
Units operating without NOx, CO, or ammonia CEMS	• Conduct source test simultaneously for NOx, CO, and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO, NOx, and ammonia emission limit • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx, CO, and ammonia emissions limits prior to resuming annual source tests

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Combustion Equipment	Source Test Schedule
Units operating with NOx CEMS and without CO and ammonia CEMS	• Conduct source test for CO and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO and ammonia emission limit • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the CO and ammonia emissions limits prior to resuming annual source tests
Units operating with NOx and CO CEMS and without ammonia CEMS	• Conduct source test for ammonia quarterly during the first 12 months of being subject to an ammonia South Coast AQMD permit limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to an ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests
Units operating with NOx and ammonia CEMS and without CO CEMS	• Conduct source test for CO within 12 months from previous source test and every 12 months thereafter
Units operating with ammonia CEMS and without NOx or CO CEMS	• Conduct source tests to determine compliance with NOx and CO emission limits pursuant to Table 7

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~~(4)~~(5) An owner or operator that elects to install and operate a CEMS to demonstrate compliance with the applicable Rule 1109.1 Emission Limits or ammonia South Coast AQMD permit limit at the corresponding percent O_2 correction shall meet the CEMS requirements under subdivision (j).

~~(5)~~(6) An owner or operator of with a ~~unit~~Unit subject to a Rule 1109.1 Emission Limit

or ammonia South Coast AQMD permit limit, that is not required to install and operate a CEMS pursuant to subdivision (i) and has not conducted a source test within the schedule in Table 7 or Table 8, shall conduct a source test within:

(A) Six months from being subject to the Rule 1109.1 Emission Limit for ~~units~~Units with a rated heat input capacity greater than or equal to 20 MMBtu/hour.

(B) 12 months from being subject to the Rule 1109.1 Emission Limit for ~~units~~Units with a rated heat input capacity less than 20 MMBtu/hour.

~~(6)~~(7) An owner or operator of a new or modified ~~unit~~Unit shall conduct the initial source tests within six months from commencing operation.

~~(7)~~(8) An owner or operator of a ~~unit~~Unit required to conduct a source test pursuant to subdivision (k) shall:

(A) For ~~units~~Units that receive a South Coast AQMD Permit to Construct to comply with Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of ~~at least~~no less than 15 minutes but no longer than 2 hours, for approval ~~within 60 days after the Permit to Construct was issued~~ at least 90 days prior to conducting the source test unless otherwise approved by the Executive Officer;

(B) For ~~units~~Units that receive a South Coast AQMD permit condition that limits NOx or CO to a Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of ~~at least~~no less than 15 minutes but no longer than 2 hours, for approval within 60 days after being subject to a Rule 1109.1 Emission limit, unless otherwise approved by the Executive Officer, and

(C) Conduct the source test within 90 days after a written approval of the source test protocol by the Executive Officer is distributed unless otherwise approved by the Executive Officer.

~~(8)~~(9) At least one week prior to conducting a source test, an owner or operator of

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a ~~unit~~Unit shall notify the Executive Officer by calling 1-800-CUT-SMOG of the intent to conduct source testing and shall provide:

(A) Facility name and identification number;

(B) Device identification number; and

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(C) Date when source test will be conducted.

~~(9)~~(10) Unless requested by the Executive Officer, after the approval of the initial source test protocol pursuant to paragraph (k)(7), an owner or operator is not required to resubmit a source test protocol for approval pursuant to paragraph (k)(7) if:

(A) The method of operation of the ~~unit~~Unit has not been altered in a manner that requires a South Coast AQMD permit application submittal;

(B) Rule or South Coast AQMD permit emission limits have not become more stringent since the previous source test;

(C) There have been no changes in the source test method that is referenced in the approved source test protocol; and

(D) The approved source test protocol is representative of the operation and configuration of the ~~unit~~Unit.

~~(10)~~(11) An owner or operator of a ~~unit~~Unit shall conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program:

(A) Using a South Coast AQMD approved source test protocol;

(B) Using at least one of the following test methods:

(i) South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or

(ii) South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);

(iii) South Coast AQMD Source Test Method 207.1 for Determination of Ammonia Emissions from Stationary Sources; or

(iv) Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

(C) During operation other than startup and shutdown; and

(D) In as-found operating condition.

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~~(11)~~(12) An owner or operator of a ~~unit~~Unit shall submit all source test reports, including the source test results and a description of the ~~unit~~Unit tested, to the Executive Officer within 60 days of completion of the source test.

~~(12)~~(13) Emissions determined to exceed any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall constitute a violation of the rule.

~~(13)~~(14) An owner or operator of a ~~unit~~Unit that exceeds any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall inform the Executive Officer within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known.

(l) Diagnostic Emission Checks

(1) An owner or operator of a ~~unit~~Unit required to perform a source test every 36 months pursuant to subdivision (k) shall:

(A) Perform diagnostic emissions checks of NOx, CO, and O_2 emissions, with a portable NOx, CO, and O_2 analyzer that is calibrated, maintained and operated in accordance with manufacturers specifications and recommendations of the South Coast AQMD Combustion Gas Periodic Monitoring Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Combustion Sources Subject to Rules 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, 1146 – Emissions of Oxides of Nitrogen From Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, and 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters.

(B) Conduct the diagnostic emission checks by a person who has completed an appropriate training program approved by South Coast AQMD in the operation of portable analyzers and has received a certification issued by the South Coast AQMD.

(C) Conduct the diagnostic test every 365 days or every 8760 operating hours, whichever occurs earlier.

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(2) A diagnostic emissions check that finds the emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall not constitute a violation of this rule if an owner or operator corrects the problem and demonstrates compliance with another diagnostic emissions check within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known, or shut down the ~~unit~~Unit by the end of an operating cycle, whichever is sooner. Any diagnostic emission check conducted by South Coast AQMD staff that finds emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall be a violation.

(m) Monitoring, Recordkeeping, and Reporting Requirements

(1) Operating Log

An owner or operator of a ~~unit~~Unit shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Time and duration of startup and shutdown events;

(B) Total hours of operation;

(C) Quantity of fuel; and

(D) Cumulative hours of operation to date for the calendar year.

(2) An owner or operator of a ~~facility~~Facility that elects to meet the NOx emission limits in an approved B-Cap pursuant to paragraph (e)(2) shall:

(A) Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for those ~~units~~Units without CEMS;

(B) Maintain daily records of mass emissions, in pounds (lbs) per day, from all ~~units~~Units included in an approved B-Cap including:

(i) Emissions during start-ups, shutdowns, and maintenance;

(ii) CEMS data identified as invalid and justification;

(iii) Data substituted for missing data pursuant to paragraph (j)(5);

(C) Demonstrate compliance with the Facility BARCT Emission Target in the B-Cap on a daily basis from 365-day rolling average;

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(3) An owner or operator subject to the interim emission rate pursuant to paragraph (f)(2) shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Actual daily mass emissions, in lbs., for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour;

(B) Combined maximum rated heat input for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour; and

(C) Calculated interim NOx emission rate pursuant to Attachment A Section (A-2) of this rule.

(4) An owner or operator of a ~~unit~~Unit shall keep and maintain the following records on-site for five years, except that all data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours, and shall make them available to the Executive Officer upon request:

(A) CEMS data;

(B) Source tests reports;

(C) Diagnostic emission checks; and

(D) Written logs of startups, shutdowns, and breakdowns, all maintenance, service and tuning records, and any other information required by this rule.

(5) An owner or operator of a boiler or process heater that is exempt from the applicable Table 1 emission limits pursuant to paragraphs (n)(5) and (n)(6), or an owner or operator of a flare that is exempt from the applicable Table 1 emission limits pursuant to subparagraph (n)(8)(A) shall:

(A) Within 90 days of [*DATE OF ADOPTION*], install and operate a non-resettable totalizing time meter or a fuel meter unless a metering system is currently installed and the fuel meter is approved in writing by the Executive Officer.

(B) Within 90 days of [*DATE OF ADOPTION*], each non-resettable totalizing time meter or a fuel meter required under subparagraph (m)(4)(A) that requires dependable electric power to operate shall be equipped with a permanent supply of electric power that cannot be unplugged, switched off, or reset except by the main power supply circuit for the building and associated equipment or the safety shut-off switch.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(C) Ensure that the continuous electric power to the non-resettable totalizing time meter or fuel meter required under subparagraph (m)(4)(A) may only be shut off for maintenance or safety.

(D) Within 90 days of [*DATE OF ADOPTION*], ensure that each non-resettable totalizing time meter or fuel meter is calibrated and recalibrate the meter annually, thereafter, based on the manufacturer's recommended procedures. If the non-resettable totalizing time or fuel meter was calibrated within one year prior to [*DATE OF ADOPTION*], the next calibration shall be conducted within one year of anniversary date of the prior calibration.

(E) Monitor and maintain hours of operation records as follows:

(i) For the hours per year validation, using a calibrated non-resettable totalizing time meter or equivalent method approved in writing by the Executive Officer; or

(ii) For the annual throughput limit equivalent to hours per year validation, using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer.

(6) An owner or operator of a vapor incinerator that is exempt from the applicable Table 1 NOx emission limits pursuant to paragraph (n)(9) shall record:

(A) The annual throughput using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer; and

(B) Emissions using a source test pursuant to subdivision (k) or by using a default emission factor approved in writing by the Executive Officer.

(7) An owner or operator of a ~~unit~~Unit subject to the compliance schedule in subparagraphs (d)(3)(B), (d)(4)(B), and (g)(3)(B) shall maintain records of burner replacement, including number of burners and date of installation.

(8) An owner or operator of a ~~unit~~Unit subject to the compliance schedule in subparagraph (g)(3)(A) shall maintain records of the date the existing post-combustion control equipment was installed or replaced.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(n) Exemptions

(1) Boilers or Process Heater with a Rated Heat Input Capacity 2 MMBtu/hour or less

The provisions of this rule shall not apply to an owner or operator of a boiler or process heater with a rated heat input capacity 2 MMBtu/hour or less that are fired with liquid and/or gaseous fuel and used exclusively for space or water heating and are subject to Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters.

(2) Low-Use Boilers with a Rated Heat Capacity of less than 40 MMBtu/hour

An owner or operator of a boiler with a rated heat capacity of less than 40 MMBtu/hour that operates 200 hours or less per calendar year, or with an annual throughput limit equivalent to 200 hours per calendar year, shall be exempt from the requirements in:

(A) Subdivisions (d) provided:

(i) The boiler has an enforceable South Coast AQMD permit conditions that limits the operating hours to 200 hours or the annual throughput equivalent to 200 hours; and

(ii) The boiler operates in compliance with the permit conditions pursuant to clause (n)(2)(A)(ii).

(B) Subdivisions (k) and (l) provided the ~~unit~~Unit is not included in an approved B-Cap.

(3) Low-Use Process Heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour

An owner or operator of a process heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour that is fired at less than 15 percent of the rated heat input capacity on an annual basis, shall be exempt from the applicable emission limits in Table 1, Table 2, and an approved B-Plan.

(4) An owner or operator of a FCCU that must bypass the post-combustion air pollution control equipment to conduct boiler inspections required under California Code of Regulations, Title 8, Section 770(b) shall be exempt from the applicable Rule 1109.1 Emission Limits during the required boiler inspections.

(5) FCCU Startup Heater

An owner or operator of a process heater which is used only for startup of a FCCU and that process heater is operated for 200 hours or less per calendar year shall be exempt from the requirements in:

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(A) Subdivisions (d) provided:

(i) The process heater or boiler has a South Coast AQMD permit that specifies conditions that limits the operating hours to 200 hours or less; and

(ii) The process heater or boiler operates in compliance with the permit condition pursuant to clause (n)(5)(A)(i).

(B) Subdivisions (k) and (l) provided the ~~unit~~Unit is not included in an approved B-Cap.

(6) Startup or Shutdown Boilers at Sulfuric Acid Plants

An owner or operator of a process heater used for startup or a boiler used during startup or shutdown at a sulfuric acid plant that does not exceed 90,000 MMBtu of annual heat input per calendar year shall be exempt from the requirements in subdivisions (d), (i), (j), and (k) provided:

(A) The process heater or boiler has a South Coast AQMD permit that specifies conditions that limits the heat input to 90,000 MMBtu or lower per calendar year; and

(B) The process heater or boiler operates in compliance with the South Coast AQMD permit condition specified in subparagraph (n)(6)(A).

(7) Boiler or Process Heater Operating Only the Pilot

An owner or operator of a boiler or process heater operating only the pilot prior to startup or after shutdown shall be exempt from the emission limits in paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 3, an approved B-Plan, or an approved B-Cap and may exclude those emission from the rolling average calculation pursuant to Attachment A of this rule.

(8) Flares

(A) An owner or operator of a flare that emits less than or equal to 550 pounds of NOx or less per year shall be exempt from the requirements in subdivisions (d), (g) and (k), provided:

(i) The flare has enforceable South Coast AQMD permit conditions that limits the emissions to not exceed 550 pounds of NOx per year; and

(ii) The flare is in compliance with the permit condition pursuant to clause (n)(8)(A)(i).

(B) An owner or operator of an open flare, which is an unshrouded flare, shall not be required to conduct source testing pursuant to subdivision (k).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(9) Vapor Incinerators

An owner or operator of a vapor incinerator that emits less than 100 pounds of NOx per year shall be exempt from the requirements in subdivision (d) provided the vapor incinerator:

(A) Has enforceable South Coast AQMD permit conditions that limit NOx emissions to less than 100 pounds of NOx per year through operating hours or annual throughput; and

(B) Operates in compliance with the permit condition pursuant to subparagraph (n)(9)(A).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT A

SUPPLEMENTAL CALCULATIONS

(A-1) Rolling Average Calculation for Emission Data Averaging

$$C_{Avg} = \sum_{i=t}^{t+N-1} C_i/N$$

Where:

C_{Avg} = The average emission concentration at time t

t = Time of average concentration (hours)

C_i = The measured or calculated concentration for a ~~unit~~Unit with a CEMS at
the i^{th} subset of data; one-hour for a ~~unit~~Unit with an averaging time of
24 hours or less and 24-hour for a ~~unit~~Unit with an averaging time of
greater than 24 hours

N = Averaging time (hours).

(A-2) Interim NOx Emission Rate Calculation

An owner of operator shall calculate interim NOx emission rates as follows:

(A-2.1) Hourly Mass Emissions (lbs/hour)

Sum the actual annual mass emissions of all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour and any boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS, and divide by 8760 hours for lbs per hour.

(A-2.2) Combined Maximum Heat Input (MMBtu/hour)

Sum the combined maximum rated heat input for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour and any boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS.

(A-2.3) Interim Facility Wide NOx Emission Rate (lbs/MMBtu)

Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim NOx emission rate.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT B
CALCULATION METHODOLOGY FOR THE I-PLAN, B-PLAN, AND B-CAP

The purpose of this attachment is to provide details regarding how key elements of the I-Plan, B-Plan, and B-Cap are calculated. Key calculations provided in this attachment include: Baseline Unit Emissions and Baseline Facility Emissions; Final Phase Facility BARCT Emission Target; Total Facility NOx Emission Reductions; Phase I, Phase II, or Phase III Facility BARCT Emission Target; Phase I, Phase II or Phase III BARCT Equivalent Mass Emissions for a B-Plan; and Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap.

(B-1) Baseline Unit Emissions and Baseline Facility Emissions

Baseline Unit Emissions shall be determined by the Executive Officer based on the applica7ble 2017 NOx Annual Emissions Reporting data, or another representative year, as approved by the Executive Officer, expressed in pounds per year. Baseline Facility Emissions are the sum of all the Baseline Unit Emissions subject to this rule and shall not include Baseline Unit Emissions for ~~units~~Units that are operational on and after [*DATE OF ADOPTION*].

(B-2) Final Phase Facility BARCT Emission Target

The Final Phase Facility BARCT Emission Target is the Phase II Facility BARCT Emission Target for an I-Plan option with two phases or the Phase III Facility BARCT Emission Target for an I-Plan option with three phases. The Final Phase Facility BARCT Emission Target is used to establish the Phase II or Phase III BARCT Emission Target for a B-Cap. To establish the Final Phase Facility BARCT Emission Target, the owner or operator must select if the basis of the emission target for each ~~unit~~Unit will be based on Table 1 or Table 2 NOx concentration limits. The owner or operator shall only select Table 2 NOx concentration limits if the requirements of subparagraphs (d)(2)(A) and (d)(2)(B) for the Conditional NOx Limits are met or if the ~~unit~~Unit is identified in Attachment D. For all other ~~units~~Units, the owner or operator shall use NOx limits from Table 1 as the basis of the Facility BARCT Emission Target. To calculate the Final Phase Facility BARCT Emission Target for B-Cap, the owner or operator shall use NOx concentration limit of Table 1 for the ~~units~~Units that will be decommissioned.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-2.1) The Final Phase Facility BARCT Emission Target for a ~~facility~~Facility complying with NOx emission limits in Table 1, an approved B-Plan or an approved B-Cap shall be calculated using the following equation:

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N = Number of included ~~units~~Units in B-Plan or B-Cap

$C_{\text{Table 1 or Table 2}}$ = The applicable NOx concentration limit for each ~~unit~~Unit i included in B-Plan or B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in B-Plan

Baseline Unit Emissions = Baseline Unit Emissions for ~~unit~~Unit i as defined in subdivision (c) and included in the I-Plan, B-Plan or B-Cap as determined pursuant to section (B-1).

(B-3) Calculating Total Facility NOx Emission Reductions

Total Facility NOx Emission Reductions is the total reduction in NOx mass emissions per ~~facility~~Facility or ~~facilities~~Facilities with the same ownership that would have been achieved if all ~~units~~Units met the NOx concentration limits in Table 1 or Table 2 of this rule based on the Baseline Facility Emissions.

(B-3.1) For a ~~facility~~Facility complying with NOx emission limits in Table 1 or Table 2, an approved B-Plan or an approved B-Cap, the Total NOx Emission Reductions is the difference between Baseline Facility Emissions and the Final Phase Facility BARCT Emission

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Target.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

$$\text{Total Facility NOx Emission Reductions} = \text{Baseline Facility Emissions} - \text{Final Phase Facility BARCT Emission Target}$$

(B-4) Calculating Phase I, Phase II, or Phase III Facility BARCT Emission Target
The Phase I, Phase II, or Phase III Facility BARCT Emission Targets are the total NOx mass emissions per ~~facility~~Facility based on the Total Facility NOx Emission Reductions and the Percent Reduction Target of Phase I, Phase II or Phase III of an I-Plan option in Table 6. ~~For a B-Cap, each phase Facility BARCT Emission Targets shall be reduced by 10 percent.~~

(B-4.1) For the B-Plan and the B-Cap, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase I Facility BARCT Emission Target}_{\text{B-Plan}} = \text{Baseline Emissions} - (\text{Phase I Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})$$

~~(B-4.2) For the B-Cap, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions, less 10 percent.~~

$$\cancel{\text{Phase I Facility BARCT Emission Target}_{\text{B-Cap}} = [\text{Baseline Emissions} - (\text{Phase I Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})] \times 0.9}$$

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(B-4.3) For the B-Plan and the B-Cap, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase II Facility BARCT Emission Target}_{B-Plan} = \text{Baseline Emissions} - (\text{Phase II Percent Reduction Target} \times \text{Total NOx Emission Reductions})$$

~~(B-4.4) For a B-Cap, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.~~

$$\cancel{\text{Phase II Facility BARCT Emission Target}_{B-Cap} = [\text{Baseline Emissions} - (\text{Phase II Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})] \times 0.9}$$

(B-4.5) For thea B-Plan and the B-Cap, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.

$$\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Plan} = \text{Final Phase Facility BARCT Emission Target}$$

~~(B-4.6) For a B-Cap, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.~~

$$\cancel{\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Cap} = (\text{Final Phase Facility BARCT Emission Target}) \times 0.9}$$

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-5) Calculating Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions for a B-Plan

The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies designed to meet Phase I, Phase II, or Phase III target reductions in an I-Plan. The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions incorporate the Alternative BARCT NOx Limit for Phase I, Phase II, or Phase III each of the ~~units~~Units included in different phases of the I-Plan. The Alternative BARCT NOx Limits are the ~~unit~~Unit specific NOx concentration limit that are selected by the owner or operator in the B-Plan to achieve the Facility BARCT Emission Targets in the aggregate, where the NOx and CO
concentration limits will include the corresponding percent O_2 correction based on the averaging time pursuant to Table 1 or subdivision (k), whichever is applicable. For the B-Plan, decommissioned ~~units~~Units shall be removed from the Baseline Facility Emissions and the Facility BARCT Emission Targets.

(B-5.1) For a B-Plan, the Phase I BARCT Equivalent Mass Emissions for all ~~units~~Units included in a B-Plan shall be calculated using the following equation:

$$\text{Phase I BARCT Equivalent Mass Emissions}_{B-Plan} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N = Number of included ~~units~~Units in B-Plan under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Plan for ~~unit~~Unit i included in the B-Plan

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in the B-Plan

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Baseline Unit Emissions = Baseline Unit Emissions for ~~unit~~Unit i as

defined in subdivision (c) and included in the B-Plan.

(B-5.2) For a B-Plan, the Phase II and if applicable, Phase III Equivalent Mass Emissions for each ~~unit~~Unit included in a B-Plan shall be calculated using the equation for Section B-5.1, with the use of the Alternative BARCT NOx Limit for Phase II and Phase III, if applicable.

(B-6) Calculating Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap

The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies. The Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions must be at or below the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan. Under the B-Cap, there are three emission reduction strategies that can be used to meet the Facility BARCT Emission Targets: Establishing an Alternative BARCT NOx Limit, Permanently Decommissioning Units, Replacing Units, and Reducing Throughput for Units. The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions calculation for the B-Cap acknowledges the three emission reduction strategies for each phase of the I- Plan. The Alternative BARCT NOx Limits are the ~~unit~~Unit specific NOx concentration limits that are selected by the owner or operator in the B-Cap to achieve the Final Phase Facility BARCT Emission Target in the aggregate,

where the NOx concentration limit will include the corresponding percent O_2 correction, CO emission limit, and averaging time per Table1. The emission reductions from Decommission Units shall be incorporated in B-Cap pursuant to section (B-2.2). Other reductions in mass emission reductions to demonstrate that the BARCT B-Cap Annual Emissions include emission reductions from reduced throughput, efficiency, reduced capacity, and any other strategy to reduce mass emissions.

(B-6.1) The Phase I BARCT B-Cap Annual Emissions for each ~~unit~~Unit included in a B-Cap shall be calculated using the following equation ~~where the Unit Throughput Reductions calculated pursuant to Section B-7~~.

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$$\text{Phase I BARCT B} - \text{Cap Annual Emissions}_{B-Cap} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})$$

Where:

N = Number of included ~~units~~Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Cap for ~~unit~~Unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions as defined in subdivision (c) and for ~~unit~~Unit i included in the B-Cap

Throughput or Other Reductions = Emission reductions occurred from other than reducing the concentration limit.

(B-6.2) For a B-Cap, the emission reductions the Phase II and if applicable, Phase III BARCT B-Cap Annual Emissions for each ~~unit~~Unit included in a B-Cap shall be calculated using the equation for Section B-6.1, with the use of three emission reduction strategies for Phase II and Phase III, if applicable.

(B-7) Emissions Reductions from Decommissioned Unit

For a B-Cap, emission reductions from decommissioned ~~units~~Units can be used to meet a Phase I, Phase II, or Phase III Facility BARCT Emission Target. The

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amount of emission reductions from a permanently decommissioned ~~unit~~Unit shall be determined using the equation below.

Emission Reductions from Permanently Decommissioned Units

$$= \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N = Number of permanently decommissioned ~~units~~Units in B-Cap

$C_{\text{Table 1}}$ = Table 1 NOx concentration limit for ~~unit~~Unit i

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in an approved B-Cap

Baseline Unit Emissions = Baseline Unit Emissions for ~~unit~~Unit i as defined in subdivision (c) and included in an approved B-Cap.

(B-8) Unit Reductions for Conditional NOx and CO Limits in Table 2

An owner or operator of a ~~unit~~Unit in a B-Plan that is demonstrating that the Unit Reduction is less than the thresholds specified in clauses (d)(2)(A)(i) or (d)(2)(A)(ii) shall calculate the Unit Reduction using the following equation:

$$\boxed{\text{Unit Reduction} = \left(1 - \frac{C_{\text{Table 1}}}{C_{\text{Baseline}}}\right) \times \text{Baseline Unit Emissions}}$$

Where:

$C_{\text{Table 1}}$ = The applicable Table 1 NOx concentration limit the ~~unit~~Unit

C_{Baseline} = Representative NOx Concentration for the ~~unit~~Unit

Baseline Unit Emissions = Baseline Unit Emissions.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT C

FACILITIES EMISSIONS – BASELINE AND TARGETS

(C-1) Baseline Facility Emissions

Table C-1 provides the Baseline Mass Emissions for Facilities with six or more ~~units~~Units. Baseline Facility Emissions in Table C-1 are based on 2017 reported emissions for Rule 1109.1 ~~units~~Units. A year other than 2017 was used for ~~units~~Units where the 2017 reported emissions were not representative of normal operations.

TABLE C-1: Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017) (tons/year)
AltAir Paramount, LLC	187165	28
Chevron Products Co.	800030	701
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	386
Phillips 66 Co/LA Refinery Wilmington PL	171107	462
Tesoro Refining and Marketing Co., LLC – Carson	174655	636
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	674
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	8
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	899
Ultramar Inc.	800026	248
Valero Wilmington Asphalt Plant	800393	5

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ATTACHMENT D

UNITS THAT QUALIFY FOR CONDITIONAL LIMITS IN B-PLAN AND B-CAP

TABLE D-1: Units That Qualify for Conditional Limits in B-Plan

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
174655	D1465	427
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D159	176
800030	D160	176
800030	D161	176
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D384	48
800436	D385	24
800436	D388	147
800436	D388	147
800436	D770	63
800436	D777	146

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TABLE D-2: Units That Qualify for Conditional Limits in B-Cap

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	D33	252
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D158	204
800436	D250	89
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

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Staff Response to Commenter Letter #7:

Response to Comment 7-1:

Please see the Response to Comment 6-19.

Response to Comment 7-2:

Please see the Response to Comment 6-19.

Response to Comment 7-3:

Please refer to response to comment in the Staff Report for PAR 1304.

Response to Comment 7-4:

Staff revised most of the compliance dates to reflect a permit submittal deadline and a deadline to meet the permit limit based on the Permit to Construct or Permit to Operate issuance date. The following are responses to the two specific instances in the comment #7-4:

- Staff retained the 54-month from permit submittal date timeline for the B-Cap to be reduced. A facility complying with a B-Cap has two compliance deadlines, the time to demonstrate the individual unit is meeting the alternative BARCT NOx limits and the timeline when the "cap" is reduced to reflect the schedule in the I-Plan. The "cap" must be reduced to reflect the NOx reduction projects but it would be onerous to reduce the cap per each individual NOx reduction project; therefore, PR 1109.1 will require the cap to be reduced 54 months after the permit submittal deadline. To address the uncertainty for when a permit will be issued, PR 1109.1 includes time extensions for the 54-month deadline if a permit was issued beyond the 18-month assumption that was used for the 54-month requirement. Implementation of time extensions for the emission cap will be implemented in six-month increments.
- In paragraph (f)(7) (formerly (g)(5)), as the intent is to give an incentive for facilities to submit their permit application on time. A late permit submittal will result in a shorter timeframe for the facilities to meet the applicable concentration limits.

Regarding the provisions for the I-Plan (former paragraph (g)(2)), staff moved those provision to a separate subdivision (new subdivision (h)) but retained the former provisions (g)(2)(B) – (G). The plans (I-Plan, B-Plan, and B-Cap) are laid out in three sections:

1. The plan requirements
2. The elements the facility must submit if they elect to comply with a plan (these elements mirror the requirements in the plan)
3. The criteria the South Coast AQMD must review to approve the plan

The language is similar in each section, but they each have a different intent.

Response to Comment 7-5:

Staff concurs and revised the rule to reflect that the first demonstration of compliance for phase I of I-Plan option 4 is 365 days after January 1, 2024. Staff will provide more clarification regarding the demonstration of compliance dates for multi-day rolling averages in the staff report.

Response to Comment 7-6:

Staff concurs with the comment and revised the language to provide more clarification on CO limits. Staff revised the language to add a new term for "Corresponding CO Concentration Limit", that corresponds to the referenced NOx concentration limit, at the applicable percent oxygen correction and averaging period specified in either Table 1, Table 2, Table 3, or Table 6.

Response to Comment 7-7:

Staff concurs with the comment and moved the compliance schedule requirements, including subparagraphs (d)(8) and (d)(9), to subdivision (f) – Compliance Schedule (formerly subdivision (g)).

Response to Comment 7-8:

Staff clarified the language in the provision regarding when the permit must be surrendered and will require the permits to be surrendered 54 months from the permit submittal date to align the decommissioning with the compliance schedule for the I-Plan. Staff will outline the process for surrendering the permit in the staff report.

Staff concurs with the suggested revision regarding not operating a decommissioned unit within the South Coast AQMD and will reflect that change in the rule.

Response to Comment 7-9:

As mentioned in the comment letter, the purpose of the B-Cap is to provide flexibility to achieve the BARCT emission reduction targets. Attachment B of the rule language provides an equation to calculate the BARCT B-Cap annual emissions in which the different strategies to meet the BARCT emission reduction targets have been considered. The facility selected alternative BARCT NOx limit, decommissioning, throughput, and other reduction strategies have been included to support that flexibility. The rule language has been revised to clarify that those strategies will also be considered when calculating the BARCT B-Cap annual emissions. The "other reductions" term refers to other strategies that an operator can take to reduce the mass emissions. Hence, as long as the facility's mass emissions is under the facility BARCT emission target at each phase at or before the corresponding compliance dates in the rule, there would be no penalty for the facility under PR 1109.1.

Staff does not agree that a facility complying with a B-Cap should not be required to comply with a NOx concentration limit in a permit. PR 1109.1 will require all units to have an enforceable permit limit upon full rule implementation, in part, to satisfy the AB 617 requirement that the facilities transition to command-and-control regulatory structure and the highest priority should be assigned to those permitted units that have not modified emissions related permit conditions for the greatest period of time. The B-Cap is an alternative compliance option to meeting the NOx concentration limits, which includes the averaging periods specified in Table 1 and Table 2. Allowing a 365-day average for each individual Unit is a weakening of the requirements and would no longer be representative of the averaging periods specified in Table 1 and Table 2. In addition, a 365-day average is inequitable to operators that elect to use a B-Plan, as they are held to the averages specified in Table 1 and Table 2.

In addition, the maximum alternative BARCT NOx concentration limits for the B-Cap will results in all units having some level of NOx emission controls. The maximum alternative BARCT NOx concentration limits are required for the B-Cap because the facility could achieve significant emission reductions from decommissioning units allowing other units not to install any NOx controls, running counter to AB 617.

Response to Comment 7-10:

The BARCT assessment based on third party consultants' report concluded that a 5 ppmv NOx limit, as demonstrated based on a 24-hour average, is technically feasible for boilers and heaters. The Norton Engineering Report noted:

> "*An averaging time of 24 hours allows the operators an appropriate window of time to see a meaningful fluctuation in the NOx emission level, diagnose the problem (if it is not a routine day-to-day event) and take the necessary corrective actions(s) before the NOx BARCT emission limit is exceeded*".

Facilities not complying with a B-Plan or a B-Cap will have to comply the Table 1 NOx emission limit of 5 ppmv as demonstrated based on a 24-hour average which has been shown to be feasible. Hence, a 24-hour averaging time for units complying with a B-plan or B-Cap that can potentially have higher NOx concentrations would be clearly feasible.

Response to Comment 7-11:

- Staff disagrees with this comment as South Coast AQMD rule typically do not impose time limitations on the South Coast AQMD.
- Please see response to comment 6-15 regarding the plan approval process.
- Staff disagrees with the comment about the "mandatory off-ramps" in paragraphs (I)(6). Those provisions are needed to ensure the facilities submit complete plans and respond to information requests in a timely manner.
- Staff concurs and included a provision to clarify the plans are subject to Rule 221

Staff appreciates the comments on the preliminary draft rule language and considered the changes.

Response to Comment 7-12:

Staff concurs with the comment and revised the language in paragraph (e)(3) (formerly paragraph (f)(3)).

Response to Comment 7-13:

- Staff concurs with the change to the time extension language in formerly clause (h)(2)(C)(i)) from 24 month to 18 months since the compliance schedules were all based on the assumption the permit will be issued within 18 months.
- Staff concurs with the suggested revision but will require a <u>complete</u> source test protocol to be submitted at least 60 days (not 90 days) prior to conducting the source test. The 60-day requirement is a standard condition on most permits.
- Staff does not agree with the comment to add "whichever is later" to paragraph (j)(10) (formerly (h)(7)). This paragraph requires the facility to meet the compliance schedule in paragraph (f)(1) or the schedule in an approved I-Plan. The phrase "whichever is later" would not apply in this case as the facility is either complying with the schedule in the approved I-Plan or they are following the schedule in (f)(1), but not both.

Response to Comment 7-14:

- Staff disagrees that the source test schedule in a facilities permit should supersede the source test schedule in PR 1109.1.
- Staff revised the source test timing from "no less than 15 minutes but no longer than 2 hours" to "no less than 60 minutes but no longer than 120 minutes" to reflect the time required in the test method. PR 1109.1 reflects that change in the subparagraphs.
- Staff concurs with the suggestion regarding the source test protocol submission deadline and revised the rule language to reflect the suggested rule language change.
- Staff concurs and will include a 90-day deadline to submit the source test result to the South Coast AQMD.

Response to Comment 7-15:

Please see Response to Comment #6-12.

Response to Comment 7-16:

Please see Response to Comment #6-9.

Response to Comment 7-17:

Please see Response to Comment in the Staff Report for PR 429.1.

Regarding compliance with the Rule 218 Series on CEMS compliance, those requirements will apply once the facility becomes a former RECLAIM facility. Prior to exiting the RECLAIM program and becoming a former RECLAIM facility, the facility will comply with Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions.

Response to Comment 7-18:

Staff revised the rule language to correct the referenced typos. Regarding acronyms, South Coast AQMD relies on the convention to spell the word out the first time it is used and use the acronym from that point forward. The only time an acronym is included as a definition is if additional clarification is required (e.g., parts per million by volume (ppmv) was included as a definition to specify it is corrected to a dry basis at Standard Conditions for the purposes of the rule).

Response to Comment 7-19 – 7-23:

Please see Response to Comment in the Staff Report for PR 429.1.

Response to Comment 7-24 – 7-25:

Please see Response to Comment in the Staff Report for PAR 1304.

Response to Comment 7-26:

Staff appreciates the comments on the rule language and took them under consideration.