SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

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Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries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

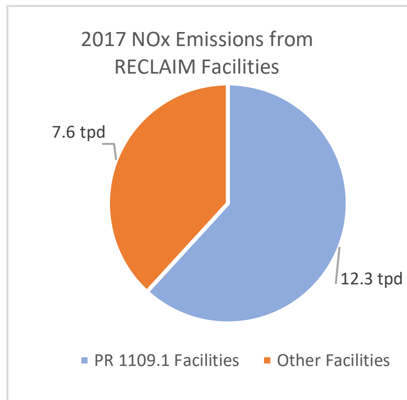
B-CAP	BARCT Equivalent Mass Cap Plan
B-PLAN	BARCT Equivalent Compliance Plan
CEMS	Continuous Emissions Monitoring System
CEQA	California Environmental Quality Act
CM	Control Measure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DCF	Discounted Cash Flow
DLN/DLE	Dry Low NOx/Dry Low Emissions
DOE	U.S. Department 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
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™	UltraCat™ 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

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) establishes NOx and Carbon Monoxide (CO) emission limits that represent Best Available Retrofit Control Technology (BARCT) for combustion equipment located at sixteen petroleum refineries and facilities with operations related to petroleum refineries (e.g., sulfur recovery plants, hydrogen plants). Implementation of PR 1109.1 is expected to achieve 6.5 to 8 tons per day of NOx emission reductions. The established BARCT NOx limits will require approximately 220 pieces of NOx equipment to be retrofit with established, achieved in practice NOx controls. These complex projects will require significant engineering, design, planning, logistics, funding, order/delivery, installation, and commissioning. Adding to the complexity of PR 1109.1 is challenges to install pollution controls on existing units, within the existing configuration of the refinery, and the customized nature of each individual emission reduction project.

PR 1109.1 will require large refinery boilers and process heaters to meet a NOx concentration limit of 5 ppmv, which will represent the lowest NOx levels in the nation. PR 1109.1 does include compliance flexibility recognizing that some units are already operating at levels near the proposed BARCT limit of 5 ppmv and/or have selective catalytic reduction (SCR) systems. For these units PR 1109.1 has conditional NOx limits that operators can meet, provided a series of conditions are met that will ensure that the greatest NOx emission reductions will be realized, while recognizing emission reduction projects with a cost-effectiveness well over $50,000 per ton of NOx reduced.



Based on the BARCT analysis for PR 1109.1, the cost-effectiveness for each class and category is less than $50,000 per ton of NOx reduced. This is a conservative estimate that assumes that each facility will comply directly with the NOx limits specified in PR 1109.1. PR 1109.1 includes two alternative implementation approaches that will help to further reduce compliance costs: the B-Plan and the B-Cap. The B-Plan allows operators to meet the NOx concentration limits in aggregate and recognizes that certain units may be more challenging than others to meet a specific NOx limit. The B-Cap achieves the same emission reductions as if the facility complied directly with the proposed NOx limits. Both alternatives will require operators to have a permit, that limits the NOx concentration for each individual unit, which currently many of the units do not have.

Although implementation of PR 1109.1 will be cost-effective, significant capital investment will be required. Staff estimates based refinery cost data that implementation costs will range from $179 million $1 billion depending on the refinery. If projects were required to be implemented outside of a refinery's turnaround window, operational disruptions would likely occur and operators would experience even higher costs. As a result, PR 1109.1 allows operators to submit an I-Plan which is an implementation plan that has specific emission targets and implementation dates. There are five I-Plan options that are designed to maximize early emission reductions, where feasible. There are certain projects, such as crude units, that have long turnaround cycles that required longer implementation timeframes.

PR 1109.1 is designed to partially implement CMB-05 of the Final 2016 Air Quality Management Plan (AQMP) and is needed to transition refineries and facilities with related operations from the

Regional Clean Air Incentives Market (RECLAIM) program to a command-and control regulatory structure. Petroleum refineries and facilities with related operations to petroleum refineries represent the largest source of NOx emissions in the RECLAIM program. In addition, PR 1109.1 includes provisions to achieve early emission reductions where feasible, consistent with California State Assembly Bill 617 which seeks 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. Three of the five major refineries are located in the AB 617 community of Wilmington, Carson, West Long Beach. Implementation of PR 1109.1 will provide needed NOx emission reductions for this community as well as other communities throughout the Basin.

CHAPTER 1 BACKGROUND

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 oxygen) for the units operated on gaseous fuel, 0.308 lb/MMBtu (approximately 250 ppmv NOx corrected to three percent oxygen) 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, 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 2012. 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 1-1 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 respectively.

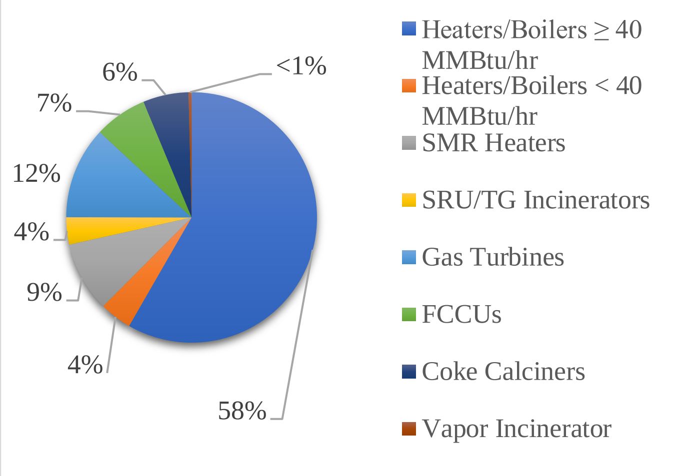


Figure 1-1 . Percentage of NOx Emissions by Equipment Category

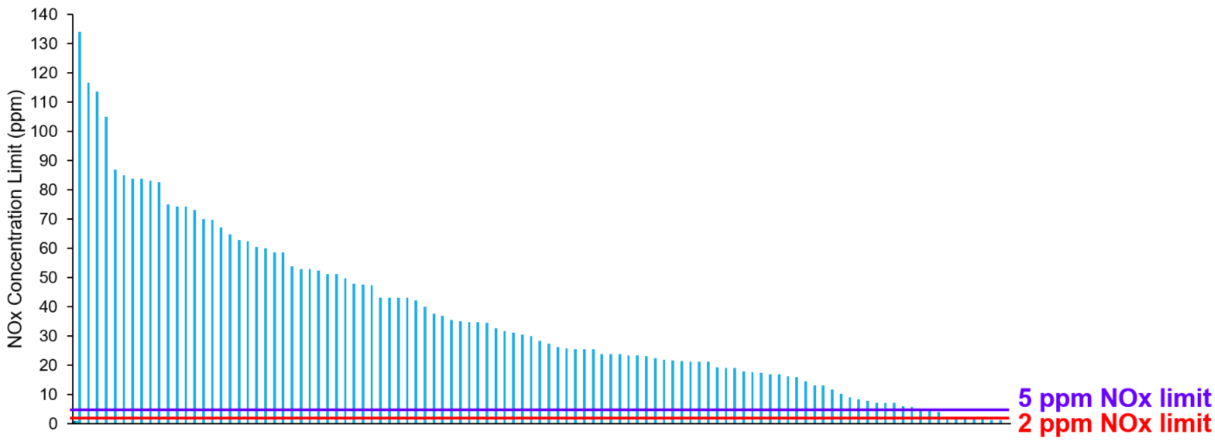


Figure 1-2. NOx Concentration Levels of Boilers and Heaters ≥40 MM Btu/hr

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].

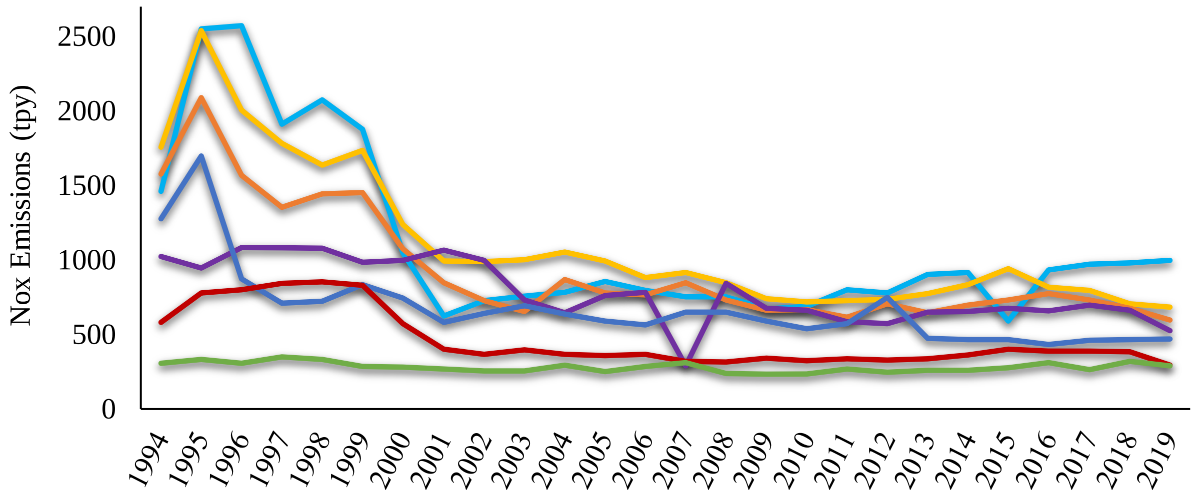


Figure 1-3. Trend of Annual NOx Emissions from Major Refineries

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. NEC was contracted to review and conduct an independent review of staff's BARCT assessment. Staff relied on NEC to address technical questions and to provide their expertise on control technology and combustion equipment.

Norton'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 cost 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 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.

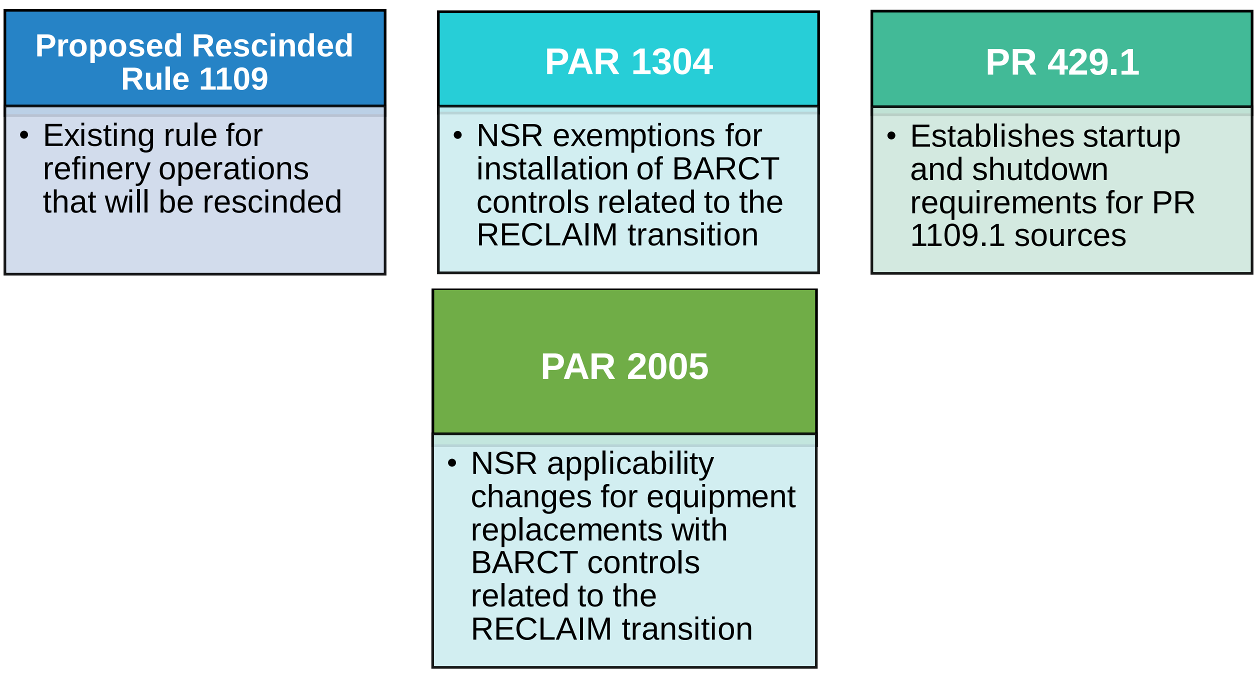


Figure 1-4. Other Related Rulemaking

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_{10} 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 during startup and shutdown events and limit the duration and frequency of those events for refineries and associated facilities that are subject to PR 1109.1. 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 Preliminary 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 Preliminary Draft Staff Report and Preliminary Draft Rule, three versions of the draft proposed rule language were released to the public between November 2020 and July 2021. The initial version of the rule language was released on October 23, 2030, the subsequent version included an alternative compliance option on December 24, 2020, and the third revision to the draft proposed rule language was released on July 21, 2021.

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

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

Date	Meeting Title	Highlights
		• 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
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

Date	Meeting Title	Highlights
		• 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)
December 10, 2020	Working Group Meeting #16 – Consultants presented Final Reports	• Revisions to CO and CEMS requirements • Updates to the implementation schedule • FERCo and NEC presentations • Revisions to PR 1109.1 based on feedback from FERCo and NEC
December 24, 2020		Released Second 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

Date	Meeting Title	Highlights
		• 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 ($\geq$ 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 • BARCT reassessment for Vapor Incinerators • BARCT Equivalent Mass Cap (B-Cap) considerations
July 21, 2021		Release Third 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

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 – August 20, 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

* 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 with 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.

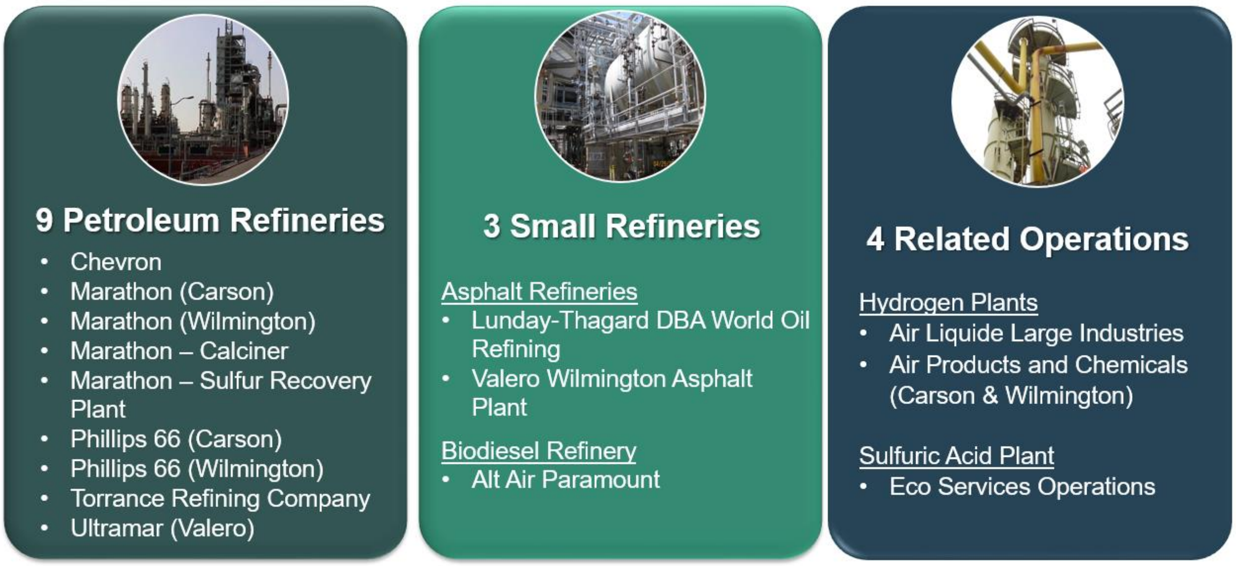


Figure 2-1. PR 1109.1 Affected Facilities

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 12.3 out of 19.9 tons per day of the NOx emissions.

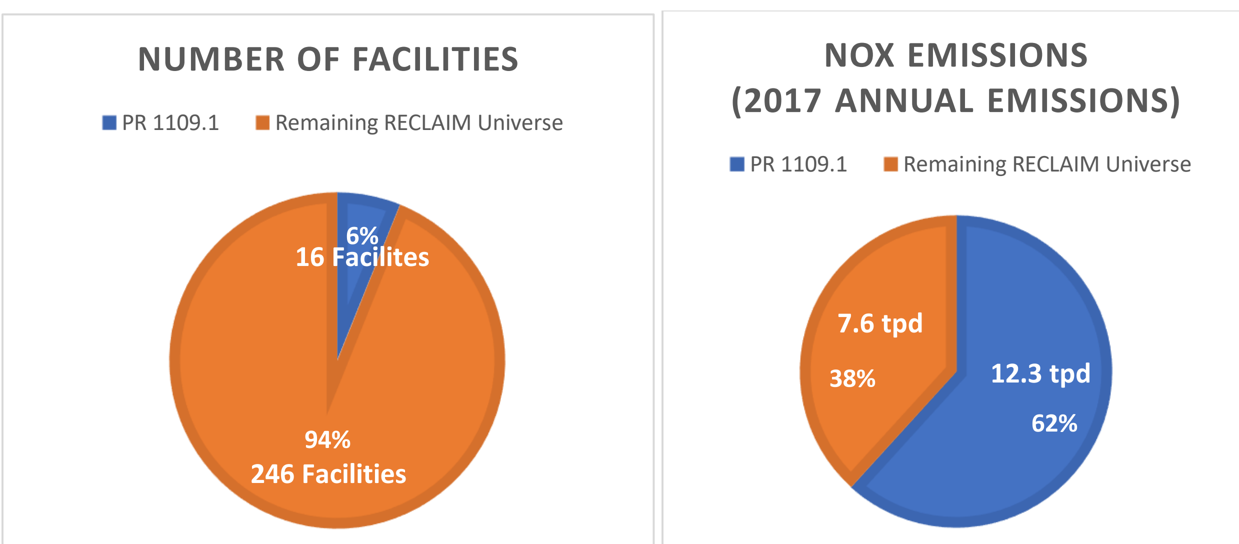


Figure 2-2. Number of Facilities and NOx Emissions PR 1109.1 versus RECLAIM

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:

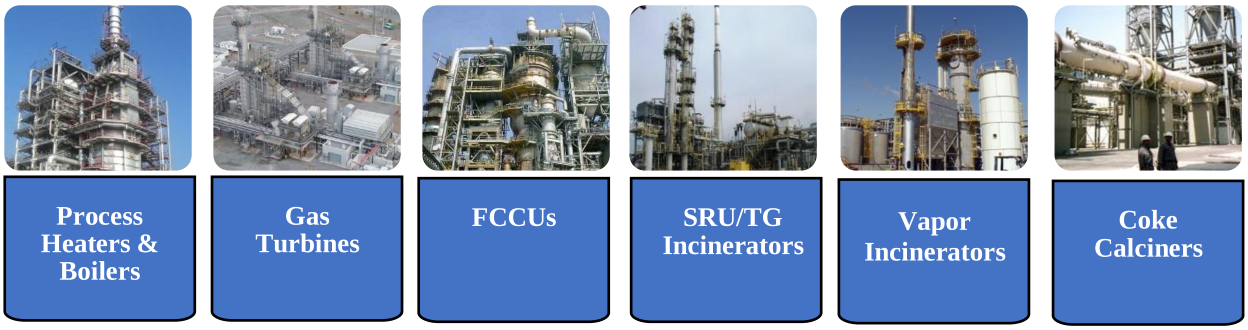


Figure 2-3: Major Categories of Equipment

Heaters and boilers are the largest equipment categories representing 80 percent of 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

	Process Heater/ SMR Heater/ Boiler	SRU/TG Incinerator	Vapor Incinerator	Gas Turbine	Start-Up Heater/ Boiler	FCCU	Coke Calciner	Flare
Lunday Thagard	5	0	2	0	0	0	0	0
Air Products-Carson	1	0	0	0	0	0	0	0
AirProdocts -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.

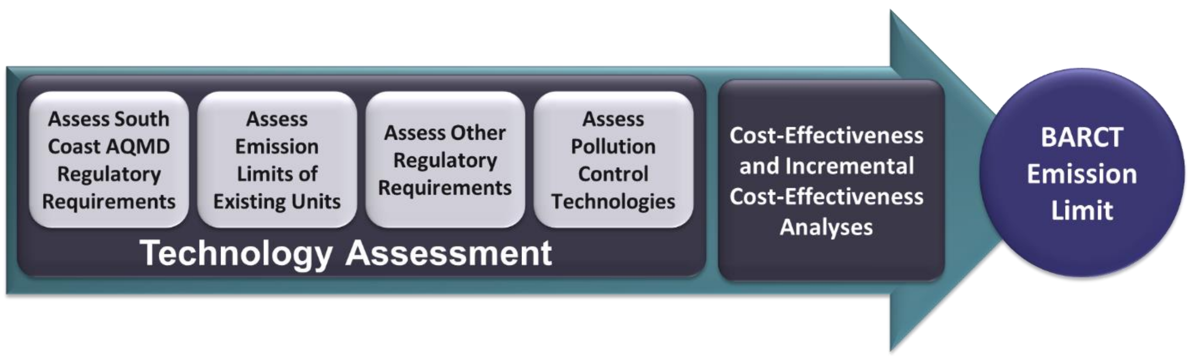


Figure 2-4. BARCT Assessment Approach

Retrofit Versus Replacement

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 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.

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

Assess Emission Limits of Existing Units

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.

Assess Other Regulatory Requirements

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, and Solex burners
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 9 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 NEC during staff's BARCT assessment. NEC 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

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)		Averaging Time (Rolling)(2)
		NOx	CO	
Boilers	<20 MMBtu/hr	40/5(3)	400	24-hour
	≥20 – <40 MMBtu/hr	40/5(3)	400	24-hour
	≥40 – ≤110 MMBtu/hr	5	400	24-hour
	>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
	≥20 – <40 MMBtu/hr	40/9(4)	400	24-hour
	≥40 – ≤110 MMBtu/hr	5	400	24-hour
	>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 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 or 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 no further action needed to be taken or minimal upgrades. Units performing below the NOx limit that represents the primary BARCT but that do not have a permit limit at that level will not be allowed to request the conditional limit. Conditional NOx and CO emission limits are listed in the individual sections for each class and category.

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.

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.

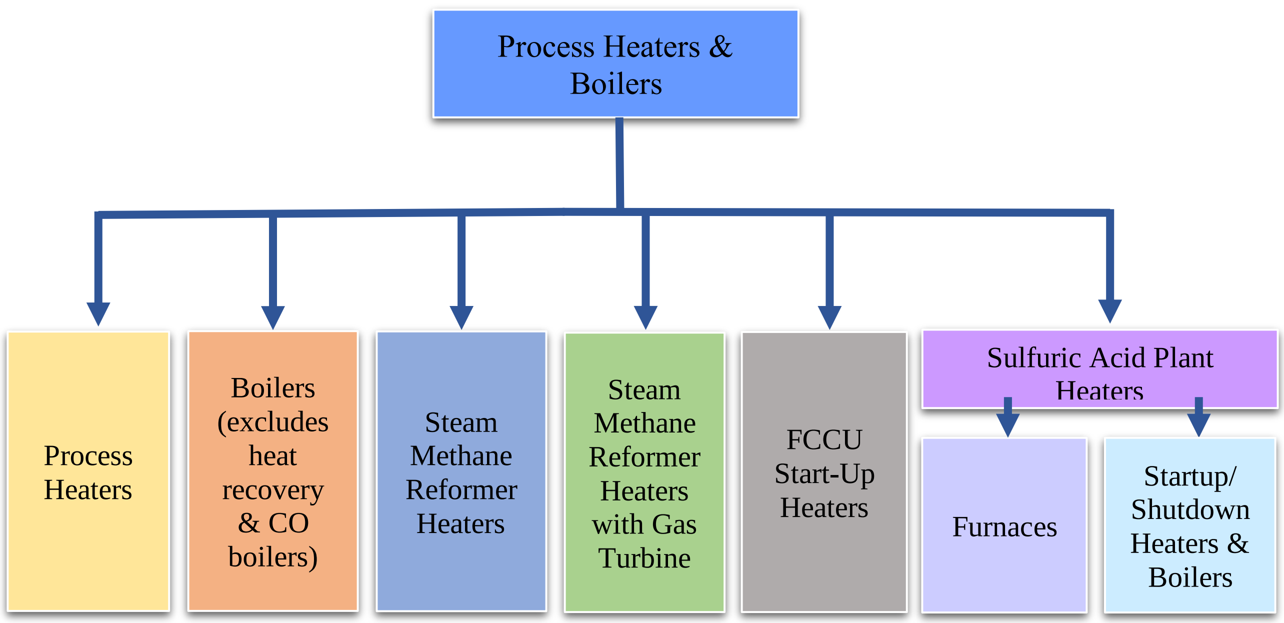


Figure 2-5. Six Major Sub-Categories of Boilers & Process Heaters Category

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 2-10. 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 2-11. 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 is 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 2-12. 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	D159	176	22
800030	Heater	D160	176	22
800030	Heater	D161	176	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	Heater	D158	204	22
800436	SMR Heater	D777	146	7.5
174655	SMR Heater	D1465	427	7.5

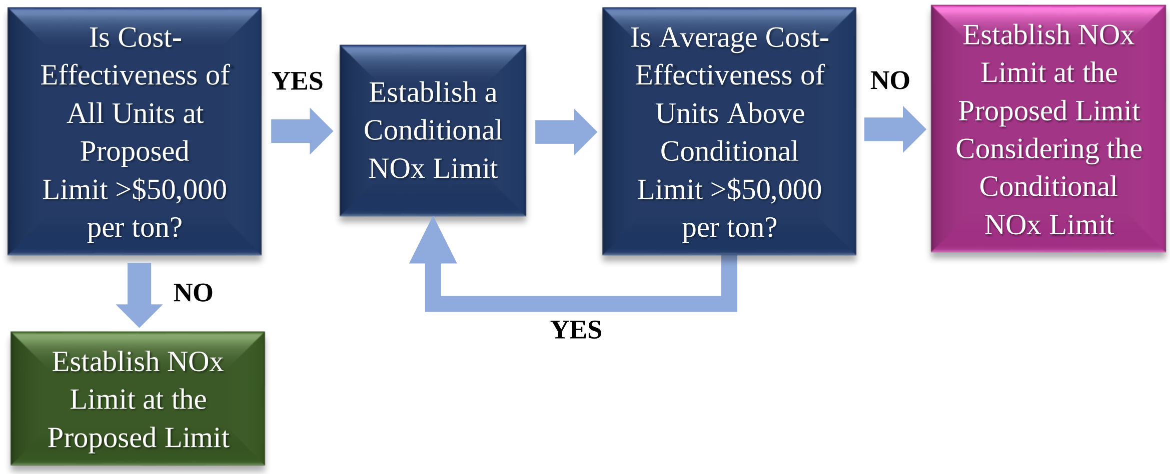
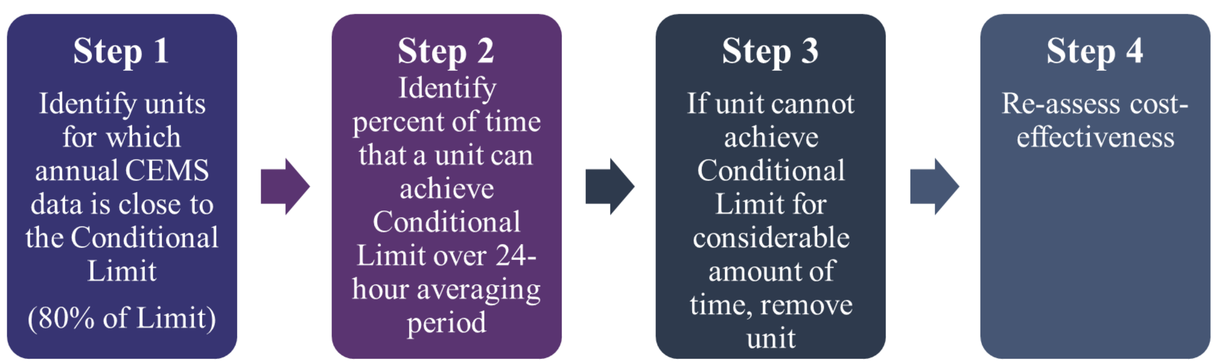


Figure 2-6: Process to Establish Conditional NOx Limits For Large Process Heaters

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 was 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 2-13. 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. 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 heater, 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 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 NEC 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, NEC 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 0.003 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 200 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 2-14. 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 2-15. 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 2-16. 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 2-17. 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 2-18. 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.

Table 2-19. 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 2-20. 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 2-21. 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 2-22. 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 2-23. 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 2-24. 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 2-25. 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 NEC'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. NEC'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 2-26. PR 1109.1 Emission Limits for Gas Turbines

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

Table 2-27. 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 2-28. 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 2-29. 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.

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 NEC's recommendation. Staff initially proposed an 8-hour averaging time but later decided to extend the averaging time to 24 hours per NEC 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 2-30. 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 2-31. 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 2-32. 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 and flares at 105 ppmv based on a 365-day average at 3percent oxygen. As no facility currently operates above 105 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

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 400-ppmv 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 2-33. 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 2-34. 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 2-35. 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	105	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 NEC recommendation, two averaging times for 2 ppmv BARCT NOx limit with a 10 percent design margin have been compared:

Table 2-36. 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 NEC 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

NEC conducted an independent review of current BARCT for stationary source categories identified by staff. NEC 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. NEC 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 NEC's comments. NEC's NOx BARCT Analysis Review can be found on the South Coast AQMD webpage.

NEC 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. NEC 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 2-37. NEC 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 Low inlet NOx (50 to 100 ppmv): 20 to 40% NOx reduction			Limited application due to geometrical considerations
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

NEC'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 NEC 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 NEC 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, NEC'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 Methan***e** *Reformer (SMR) Heaters and SMR Heaters with Gas Turbine*
For this heater category, staff relied on NEC'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. NEC 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
NEC's conclusion for the sulfuric acid furnaces agrees with staff's conclusion. Both NEC 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. NEC supports staff's proposed BARCT NOx limit of 30 ppmv with custom designed burners which can.

Fluid Catalytic Cracking Unit (FCCU)
NEC'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. NEC 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
NEC 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. NEC 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

NEC assessment concludes that NOx emissions from SRU/TG incinerators are the result of NOx concentration in the inlet vapor. NEC 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

NEC 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

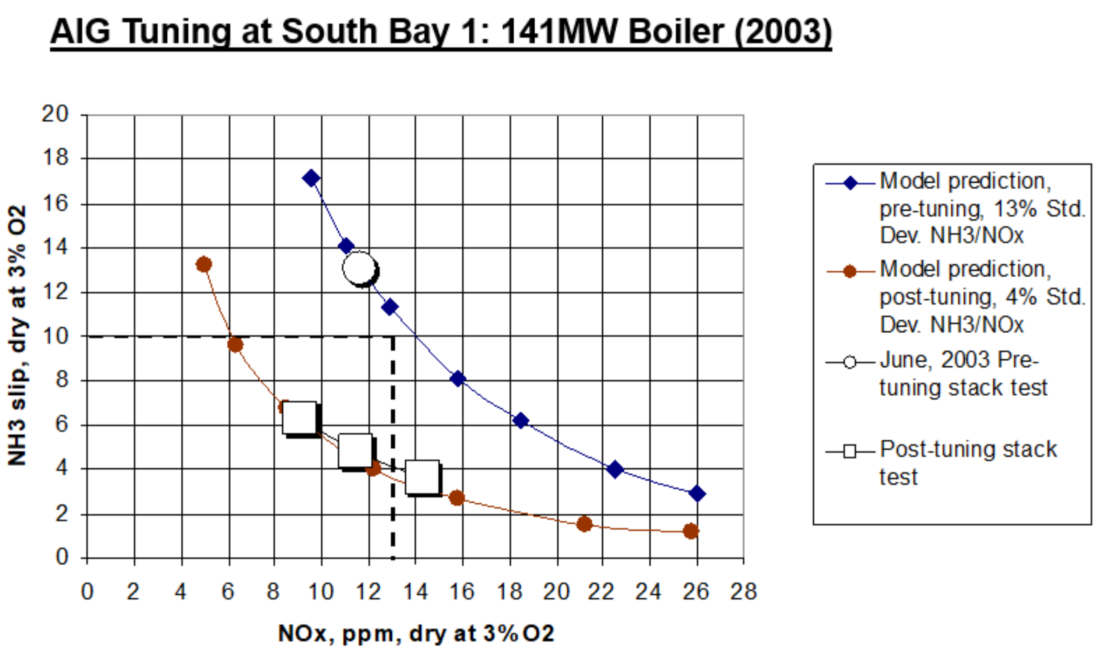
Based on the site visits, FERCo concluded that all the facilities exhibited space limitations to varying degrees. Not all open space that surrounds a unit is available for an SCR system, as open space may be necessary for maintenance work. Despite the space limitations, some facilities have devised several 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.



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 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 emission 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)	Emission Limits
(e)	B-Plan and B-Cap Requirements
(f)	Interim Limits
(g)	Compliance Schedule
(h)	Time Extensions
(i)	I-Plan, B-Plan, and B-Cap Submittal & Approval Requirements
(j)	CEMS Requirements
(k)	Source Test Requirements
(l)	Diagnostic Emission Checks
(m)	Monitoring, Recordkeeping, and Reporting Requirements
(n)	Exemptions
(Attachment A)	Rolling Average Calculation
(Attachment B)	Implementation Compliance Plan (I-Plan) Requirements
(Attachment C)	Barct Equivalent Compliance Plan (B-Plan) Requirements
(Attachment D)	Barct Equivalent Mass Cap Plan (B-Cap) Requirements
(Attachment E)	Facilities Emissions – Baseline and Targets

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 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, SRU/TG 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, refer to PR 1109.1 for complete list of definitions. The following are some other key definitions specific to PR 1109.1:

PR 1109.1 defines "facilities with the same ownership" because the alternative compliance plans and interim emission limits allow all units at facilities with the same ownership to be considered in one compliance plan and in the interim emission limits for boilers and process heaters 40 MMBtu/hour or greater.

- FACILITIES WITH SAME OWNERSHIP means facilities and their subsidiaries, or facilities that share the same Board of Directors or share the same parent corporation.

At time of this staff report, the following are the PR 1109.1 facilities with the same ownership:

Table 3-1. Facilities with 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, boilers, flares, FCCUs, gas turbines, petroleum coke calciners, process heaters, SMR heaters, sulfuric acid furnaces, SRU/TG incinerators, and vapor incinerators requiring a South Coast AQMD permit and not required to comply with another NOx emission limit in a South Coast AQMD Regulation XI rule.

Many units at PR 1109.1 are combined through common ducting to allow a single air pollution control device to control the emissions of several units. PR 1109.1 includes a definition for "units with combined stacks" to clarify how the provisions apply to those units.

- 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).

SUBDIVISION (d) – EMISSIONS LIMITS

This subdivision establishes the proposed BARCT and conditional NOx and CO emission limits for combustion equipment at petroleum refineries and facilities with operations related to petroleum refineries. PR 1109.1 Table 1 lists the NOx and CO emissions limits for different class and category of equipment subject to this rule and identifies the corresponding rolling averaging times and percent of oxygen as the basis for emissions measurement or calculation. PR 1109.1 Table 1, Table 2, and Table 3 establishes averaging times that the NOx concentration limits must be met. 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, Table 2, and Table 3 of PR 1109.1. Averaging times for units that must demonstrate compliance with a source test are required to demonstrate compliance based on a 2-hour source test pursuant to subdivision (k).

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

Unit	NOx (ppmv)	CO (ppmv)	O_2 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

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
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. Requirements, including averaging times, for units without CEMS are specified in subdivision (k).

Conditional NOx and CO Limits – Paragraph (d)(2)

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. This provision is designed to recognize that some units have existing pollution controls that are currently operating near the NOx limits in PR 1109.1 Table 1 and it is not cost-effective to require replacement or installation of additional pollution controls. PR 1109.1 includes several conditions that an owner or operator must meet if an operator elects to meet the NOx and CO limits in Table 2, in lieu of the NOx and CO limits in Table 1.

PR 1109.1 has two pathways for operators to use Table 2 conditional limits. The first pathway is through meeting all of the conditions specified under subparagraph (d)(2)(A) and (d)(2)(B). Under this first pathway, the operator must meet all of the conditions specified under subparagraph (d)(2)(A) and submit a permit application by July 1, 2022. Additional details regarding the conditions are discussed below. The second pathway is for units that are identified in Attachment D of PR 1109.1. Attachment D includes Table D-1 which applies to facilities with a B-Plan or a B-Cap and includes those units that were identified in the cost-effectiveness as part of establishing the conditional limits. Table D-2 applies to facilities with a B-Cap that have selected I-Plan Option 4 and includes those units that meet all of the conditions in subparagraph (d)(2)(A) and that have a representative NOx concentration at or below 25 ppmv. Units listed under Table D-2 were added since an operator that is implementing I-Plan Option 4 will achieve 50 to 60 percent of their targeted emission reductions by January 1, 2024. Both pathways are designed to achieve earlier NOx reductions to be consistent with the intent of AB 617.

Under subparagraph (d)(2)(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 recently installed pollution control devices, such as SCR, which can achieve the Table 1 emission 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 Table 1 NOx limit of 5 ppmv for large boilers and heaters. 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 emission limits under Table 1 of PR 1109.1.

The next two conditions are that emission reduction projects for process heaters between 40 – 110 MMBtu/hour could not have an emission reduction potential of reducing 10 tons per year or more and emission reduction projects for boilers or process heaters >110 could not have an emission reduction potential of reducing 20 tons per year or more. The potential emission reductions are based on the difference of the baseline emissions and the Table 1 concentration, scaled to the baseline emissions.

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 two conditions are that the unit must not have an existing permit limit or achieving at or below the Table 1 NOx limits. These conditions will prevent units that are achieving NOx emissions that meet the Table 1 NOx limits from electing to comply with the conditional limits. Units that meet the conditions for the Table 2 emission limits must submit a permit application by July 1, 2022 and meet the permit limits no later than 18 months from the issuance of the Permit to Construct.

For a B-Plan, an operator electing to meet the conditional NOx limit must submit a permit application by July 1, 2022, unless the unit is identified in Table D-1 of PR 1109.1. Staff is proposing July 1, 2022 to coincide with the submittal of an I-Plan and B-Plan. A commitment that an operator will be meeting the conditional NOx limit is needed to allow an 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 consistent with AB 617.

The proposed NOx and CO conditional limits are listed in the table below.

Table 3-3. PR 1109.1 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
FCCU	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. Requirements, including averaging times, for units without CEMS are specified in subdivision (k).

Proposed NOx Limits for Boilers and Process Heaters with a Rated Heat Input Capacity Less than 40 MMBtu/hr – Paragraphs (d)(3) and (d)(4)

PR 1109.1 establishes an initial NOx limit of 40 ppmv for boilers and process heaters smaller than 40 MMBtu/hr with consideration for lower NOx limits when burners are replaced. On or before January 1, 2023, operators must modify existing permits for these boilers and process heaters to limit NOx to 40 ppmv and CO to 400 ppmv at three percent O_2. CO limit, percent of O_2, and if applicable, meet the averaging time in PR 1109.1 Table 1.

The NOx limit of 40 ppmv is lowered to 5 ppmv for boilers and 9 ppmv for process heaters when either the operator 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 replacement of burners begins to be effective from July 1, 2022. Since the emission reduction technologies for process heaters are based on emerging technologies, the NOx limit of 9 ppmv is applicable ten years after rule adoption to provide time for specific emerging technologies. The cumulative burner replacement provision applies from date of rule adoption to prevent a facility from replacing burners incrementally over time in order not to trigger a retrofit. Operators are required to maintain records for burner replacement for these boilers and process heaters to track burner replacement. Staff believes that implementation of the B-Plan and B-Cap 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.

Gas Turbines Operating on Natural Gas – Paragraph (d)(5)

PR 1109.1 provides an alternative NOx emission limit of 5 ppmv (corrected to 15 percent oxygen on dry basis) based on a 24-hour rolling average, instead of the 2-ppmv and 5-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. CO Emission Limits in Table 1 and Table 2 of PR 1109.1.

Units with Combined Stacks – Paragraph (d)(6)

Paragraph (d)(6) requires units with combined stacks to meet the most stringent applicable Table 1 or Table 2 NOx limits. This provision addresses which requirements apply to combined units 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 between 40 – 110 MMBtu/hr → 40 – 110 MMBtu/hr
  - One is >40 MMBtu/hr and the other units are less → 40 – 110 MMBtu/hr

CO Limits – Paragraph (d)(7)

PR 1109.1 Table 1 and Table 2 establish CO 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 limits in permits and consistent with other rules regulating similar combustion equipment. If a unit has a CO emission limit established in a Permit to Operate before the date of rule adoption, the owner or operator must meet the CO emission limit in the Permit to Operate in lieu of the CO emission limit specified in Table 1 or Table 2 of PR1109.1. The CO permit limit can include an actual permit limit or a reference to South Coast AQMD Rule 407 – Liquid and Gaseous Air Contaminants.

Owner or operators 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 operator is required to meet the applicable CO emission limit in Table 1 or Table 2.

Provisional Averaging Time - Paragraph (d)(8)

During the rulemaking process some operators commented that achieving the shorter averaging times and lower NOx levels in PR 1109.1 will be challenging as operators are currently held to an annual compliance cycle under the RECLAIM program. Achieving the proposed NOx limits in Table 1 and 2 under PR 1109.1 will require a shorter compliance periods for all units other than the FCCUs, Petroleum Coke Calciner, and Sulfuric Acid Plants, which will be subject to 365-day rolling averages. To address this additional challenge, for units subject to a rolling average less than a 365 days, compliance with the applicable limits needs to be demonstrated six months after either the issuance of the Permit to Operate, or 36 months after the Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner. 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 (d)(9)

An owner or operator of a unit subject to a 365-day rolling average shall demonstrate compliance with the Rule 1109.1 Emission Limits beginning 14 months after either 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. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.

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

PR 1109.1 includes two alternative compliance options to directly meeting the NOx limits in Table 1 or Table 2 for operators with six or more units. Total mass emissions are calculated from all units complying with applicable Table 1 or Table 2 NOx limits with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the 5 ppmv or 9 ppmv NOx emission limit upon burner replacement after the final compliance date in the selected I-Plan option. Then, the alternative concentration limits for each unit in the B-Plan are identified and calculated to ensure that the units at those alternative concentration levels will enable the facility to achieve no greater emissions calculated with Table 1 or 2 assuming operations at 2017 levels. Those concentration limits are then set as permit requirements, allowing facilities to operate at whatever levels their permits otherwise allow.

- I-PLAN means an implementation plan for facilities with six or more units that includes an alternative implementation schedule to paragraph (g)(1) and emission reduction targets.
- B-CAP means a compliance plan that establishes a mass emission cap for all units subject to this rule that are equivalent, in aggregate, to the Facility BARCT Emission Target.
- B-PLAN is a compliance plan that allows an owner or operator to select NOx concentration limits that are equivalent, in aggregate, to the NOx concentration limits specified in Table 1 and Table 2 of this rule for units to be included in the B-Plan.

Operators can submit a B-Plan which will achieve the Table 1 or Table 2, provided conditions are met, in aggregate based on 2017 emissions. Under the B-Plan, operators would meet Alternative BARCT NOx Limits, with no mass emission cap, similar to a traditional command-and-control regulatory rule. Alternative BARCT NOx limits shall not exceed the Conditional NOx and CO limit in Table 2, if applicable. If the operator has units that are identified in Attachment D of PR 1109.1, an application is not required by July 1, 2022 as provided under subparagraph (d)(2)(C).

Alternatively, operators can submit a B-Cap where operators would meet Alternative BARCT NOx limits as well as maintaining NOx emissions below an emission cap. Emission reductions from decommissioning units and units with reduced throughputs or other emission reduction strategies would allow higher Alternative BARCT NOx Limits for other units in the B-Cap, provided the overall mass emissions are below the emissions cap and the Alternative BARCT NOx limits do not exceed the Maximum Alternative NOx concentration limits in Table 3 in PR 1109.1.

Regardless if the operator is complying with PR 1109.1 through a B-Plan or B-Cap, each and every unit must have an enforceable permit at the time of full compliance with the requirements of PR 1109.1.

Table 3-4. PR 1109.1 Table 3 – Maximum Alternative BARCT NOx Limits for a B-Cap

Unit	Alternative NOx Limit (ppmv)	O_2 Correction (%)
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3
FCCU	8 ppmv	3
Gas Turbines	5 ppmv	15
Petroleum Coke Calciner	100 tons/year	N/A
SRU/TG Incinerator	50 ppmv	3
Vapor Incinerator	40 ppmv	3

Requirements for the B-Plan and B-Cap - Paragraph (e)(1) and (e)(2)

Paragraphs (e)(1) and (e)(2) establish the requirements for the B-Plan and B-Cap, respectively. Operators must submit the B-Plan or B-Cap by July 1, 2022. Both the B-Plan and B-Cap require operators to accept permit limits that reflect the Alternative BARCT Limits in the B-Plan and B-Cap and to meet those concentration limits based on the schedule in the approved I-Plan. In the B-Cap the Alternative BARCT NOx limit cannot exceed Table 3 of PR1109.1 as shown in the table above.

Under the B-Cap, a facility 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 of a unit that is selected to be decommissioned under a B-Cap is required to reflect the emissions from the decommissioned unit as Table 1 emissions in the Phase I, Phase II, and if applicable Phase III Facility BARCT Emission Target in an approved B-Cap. 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.

PR 1109.1 includes additional requirements for the B-Cap, which include limiting the cumulative NOx emissions for all units in the B-Cap to at or below the Facility BARCT Emission Targets based on a 365-day rolling daily demonstration. The operator cannot add a new unit to the facility without the emissions from that unit being included in the B-Cap mass emissions calculation that is applicable to PR 1109.1, unless:

- All units in the approved B-Cap meet Table 1 NOx limits and applicable Table 2 NOx limits in aggregate;
- The new unit is not functionally similar to any unit that was decommissioned in the approved B-Cap;
- The new unit will not increase overall throughput of the facility; or

- The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of final phase of the Facility BARCT Emission Target in an approved B-Cap.

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. The provision to limit the NOx reductions in a B-CAP is to prevent a facility from shutting down some large emitting units in lieu of retrofitting a significant number of units at the facility.

SUBDIVISION (f) – INTERIM LIMITS

As discussed in Chapter 2, interim NOx 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. PR 1109.1 includes interim limits that are based on permit limits and actual emissions data. Except for interim limits for boilers and process heaters 40 MMBtu/hour and greater, all interim limits are a specific NOx concentration limit and provide a 365-day averaging period. PR 1109.1 is proposing a 365-day averaging period to minimize disruptions as facilities transition out of RECLAIM. Interim limits for all units except boilers and process heaters 40 MMBtu/hour and greater are provided in Table 4 of PR 1109.1 and is presented below.

Table 3-5. PR 1109.1 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
FCCU	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
SRU/TG Incinerators	100	400	3	365-day

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
SMR Heaters	20[2]	400	3	365-day
	60[3]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	105	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. Averaging times for units without CEMS are specified in subdivision (k).

2 SMR Heaters with post-combustion air pollution control equipment installed before [*DATE OF ADOPTION*].

3 SMR Heaters without post-combustion air pollution control equipment installed before [*DATE OF ADOPTION*].

Interim Limits for Boilers and Process Heaters with CEMS – Paragraph (f)(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 these units. PR 1109.1 establishes different NOx limits for all boilers and process heaters with a rated heat input capacity at or greater than 40 MMBtu/hour and the ones with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS (based on the maximum rated capacity) based on the operator choice of B-Plan or B-Cap (PR 1109.1 Table 5, provided as Table 3-6 in this Staff Report). This provision will be implemented until the last unit in this class meets the final NOx concentration limit to ensure that as units comply with the NOx concentration limit, the remaining units do not exceed the applicable threshold established in PR 1109.1 Table 5.

Table 3-6. PR 1109.1 Table 5 – Interim NOx Emission Rates for Boilers and Process Heaters

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

The calculation to determine a facility's NOx levels is included in Attachment E of the rule and as follows:

- Annual Mass Emissions (lbs/hour)
  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 8760 hours for lbs per hour.
- 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 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)
  Divide the Hourly Mass Emissions in Section (E-1.1) by the combined Maximum Heat Input in Section (E-1.2) to determine the interim facility-wide NOx emission rate.

Interim Limits for a facility that elects to comply with a B-Cap – Paragraph (f)(3)

Facilities that elect to comply with a B-Cap will not be held to the NOx concentrations limits in Table 4 or Table 5 of PR 1109.1. The interim limits are intended to prevent emission increases once a facility exists RECLAIM and before all the PR 1109.1 emission limit apply. To achieve this for the facilities complying with an approved B-Cap, facilities will be held to their Baseline Facility Emissions which is based on the 2017 annual emissions.

SUBDIVISION (G) – COMPLIANCE SCHEDULE

This subdivision establishes the implementation schedules for combustion equipment at petroleum refineries and facilities with operations related to petroleum refineries to comply with PR 1109.1 requirements. There are two main implementation pathways. The first pathway would require the operator to submit permit applications by July 1, 2023 and the second alternative pathway, which is available to facilities with six or more units, is to submit an I-Plan which is an implementation plan that includes an alternative implementation schedule with emission reduction targets.

Compliance with Table 1 – Paragraph (g)(1)

This paragraph requires an owner or operator to submit a permit application to establish a NOx in a permit on or before July 1, 2023. Operators must meet the NOx and CO concentration limits in PR 1109.1 Table 1 no later than 36 months after a Permit to Construct is issued. Operators with a Permit to Construct or a Permit to Operate that already limits the NOx concentration 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.

I-Plan Requirements – Paragraph (g)(2)

An I-Plan is an implementation plan that includes an alternative implementation schedule to paragraph (g)(1). 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 emission limits. An owner or operator with six or more units has the option to submit an I-Plan to meet the NOx and CO emission limits specified in PR 1109.1 Table 1 or Table 2 . The purpose of the I-Plan is to allow facilities the flexibility to select the group of units that will implement emission reduction projects for each phase, provided the group of units and their associated emission reductions meet the emission reduction targets established under the I-Plan which are specified in Table 6 of PR 1109.1, provided as Table 3-7 in this staff report. The I-Plan allows refineries to implement projects within their turnaround schedules to minimize operational disruptions. Staff consulted with refineries to develop the proposed I-Plan timeframes and percent reductions. The I-Plan is designed to implement the Table 1, and if eligible Table 2, the B-Plan, or the B-Cap. The I-Plan can include all the units under one facility or all the units under a facility with same ownership 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 PR 1109.1 Table 6 for the selected I-Plan option.

Table 3-7. PR 1109.1 Table 6 – I-Plan Targets and Schedule[(1)]

<table>
<tr><th></th><th></th><th>Phase I</th><th>Phase II</th><th>Phase III</th></tr>
<tr><td rowspan="3">I-Plan Option 1 B-Plan Only</td><td>Percent Reduction Targets</td><td>70</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>July 1, 2023</td><td>January 1, 2027</td><td>N/A</td></tr>
<tr><td>Compliance Date</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>NA</td></tr>
<tr><td rowspan="3">I-Plan Option 2 B-Plan Only</td><td>Percent Reduction Targets</td><td>60</td><td>80</td><td>100</td></tr>
<tr><td>Permit Application Submittal Date</td><td>July 1, 2023</td><td>January 1, 2025</td><td>January 1, 2028</td></tr>
<tr><td>Compliance Date</td><td colspan="3">later than 36 months after a Permit to Construct is issued</td></tr>
<tr><td rowspan="3">I-Plan Option 3 for B-Plan or B-Cap and as allowed pursuant to paragraph (g)(3)</td><td>Percent Reduction Targets</td><td>50</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>January 1, 2025</td><td>January 1, 2029</td><td>N/A</td></tr>
<tr><td>Compliance Date</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>N/A</td></tr>
<tr><td rowspan="3">I-Plan Option 4 for B-Cap Only</td><td>Percent Reduction Targets</td><td>50 to 60 (Still in development)</td><td>80</td><td>100</td></tr>
<tr><td>Permit Application Submittal Date</td><td>N/A</td><td>January 1, 2025</td><td>January 1, 2028</td></tr>
<tr><td>Compliance Date</td><td>January 1, 2024</td><td colspan="2">No later than 36 months after a South Coast AQMD Permit to Construct is issued</td></tr>
<tr><td rowspan="3">I-Plan Option 5 for B-Cap Only</td><td>Percent Reduction Targets</td><td>50</td><td>70</td><td>100</td></tr>
<tr><td>Permit Application Submittal Date</td><td>July 1, 2022</td><td>July 1, 2024</td><td>January 1, 2028</td></tr>
<tr><td>Compliance Date</td><td colspan="3">No later than 36 months after a South Coast AQMD Permit to Construct is issued</td></tr>
</table>

1 Percent Reduction Targets represent refinery-wide emission reductions including Facilities with Same Ownership.

Any operator that submits either a B-Plan or a B-Cap is required to submit an I-Plan. The I-Plan requirements are different for the B-Plan and B-Cap. For operators using a B-Plan, key requirement are to submit an I-Plan for review and approval by July 1, 2022, calculate the Facility BARCT Emission Target for each phase of the I-Plan, and to implement the approved B-Plan based on the schedule in the approved I-Plan that meets one of the I-Plan options in PR 1109.1 Table 6. For facilities using a B-Cap, the key requirements for the I-Plan are similar with the additional provisions for a 10 percent reduction to the Facility BARCT Emission Targets and specificity regarding when the reduction in the mass cap will occur relative to the schedule in Table 6 of PR 1109.1.

Since the B-Cap establishes a mass emissions cap compliance option, the Facility BARCT Emission Target is proposed to be reduced by 10 percent. 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. PR 1109.1 requires that the reduction in the Facility BARCT Emission Target reflecting the Percent Reduction Targets in PR 1109.1 Table 6, be applied 54 months after the permit application is required for each phase of the selected I-Plan option in PR 1109.1 Table 6. The 54-month requirement is based on 18 months between submittal of a permit application and issuance of a Permit to Construct plus 36 months to meet the Alternative BARCT NOx Limit in the approved B-Cap. For facilities with a B-Cap meeting I-Plan Option 4, the Phase I BARCT Emission Target shall be met on or before January 1, 2024.

Staff does not view the implementation period provided in Rule 1109.1 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.).

Applicability of I-Plan Option 3 – Paragraph (g)(3)

I-Plan 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 less than 40 MMBtu/hours operates with a certified CEMS, based on the maximum rated capacity. The facility would be required to perform a one-time demonstration that their applicable boilers and 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.

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

A unit complying with a Table 2 conditional limit under subparagraphs (d)(2)(A) and (d)(2)(B) will be required to submit a permit application, accept the NOx concentration limit in Table 1 and meet the NOx and CO concentration limits at the percent oxygen and averaging times in Table 1 if the NOx post-combustion air pollution control equipment is replaced for an FCCU, gas turbine fueled with natural gas, process heater with a heat input capacity at or greater than 40 MMBtu/hour, or SMR heater. A vapor incinerator complying with a Table 2 conditional limit will be required to submit a permit application, accept the NOx concentration limit in Table 1 and meet the NOx and CO concentration limits at the percent oxygen and averaging times in Table 1 if more than 50 percent of the burners are cumulatively replaced. The provision for replacing NOx post-combustion controls applies only if the post-combustion controls is greater than 50 percent of the fixed capital cost that would be required to construct a similar new unit. This provision is to ensure that if an operator is making a significant modification to the listed equipment, then the operator will be required to meet the Table 1 NOx and CO emission limits. A unit complying with Table 2 conditional limits under subparagraph (d)(2)(C) is required to submit the permit application based on their approved B-Plan or approved B-Cap. These units may select Alternative BARCT Emission Limits that are different than Table 2, but the selected Alternative BARCT Emission Limit must be incorporated into the operator's permit to operation.

Paragraph (g)(5)
If an owner or operator fails to submit a permit application when required to, the unit shall meet the applicable rule limit no more than 36 months after the application was due. This will prevent undue delays of air pollution control equipment installation because permit applications were not submitted in a timely manner.

Exempted Units - Paragraph (g)(6)
This paragraph requires units that are exempt from PR 1109.1 Table 1 NOx and CO limits under specific provisions in subdivision (n) to submit a permit application within six months from the time they exceed the applicable exemption thresholds and to meet the NOx and CO emission limit in PR 1109.1 Table 1 within 36 months after the Permit to Construct is issued.

SUBDIVISION (h) – TIME EXTENSION

PR 1109.1 allows two 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 permitting process. This subdivision establishes the criteria for time extensions, information that must be submitted, and the approval process.

Under paragraph (h)(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 twelve 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 Date 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 for main areas that will be evaluated: Delays related to missed milestones; delays due to other agency approvals; delays related to deliver of parts or equipment; and delays related to workers or services.

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 (h)(2) can also request a time extension under subparagraph (h)(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. Executive Officer will determine the time extension based on the current turnaround and the subsequent turnaround schedule. Other criteria are needed to ensure that the issuance of the Permit to Construct will 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 (h)(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.

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.

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

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

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.

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,

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.

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 review and approval/disapproval process for the I-Plan, B-Plan and B-Cap. Executive Officer will review the submitted I-Plan to ensure the information required under subparagraphs (i)(1), (i)(2) and (i)(3) is complete and accurate for I-Plan, B-Plan and B-Cap, respectively. The key elements of the I-Plan are the Percent Reduction Targets by phase listed in Table 6 of PR 1109.1 and ensuring the emission reduction projects reflect the applicable NOx emission limits under PR 1109.1 Table 1, PR 1109.1 Table 2, an approved B-Plan or an approved B-Cap. For B-Plan and B-Cap, the review of the plan ensures that the Facility BARCT Emission Target is met based on the identified units to meet PR 1109.1 Table 2 instead of Table 1 and the Alternative BARCT NOx limits that the operator determined for other units under the B-Plan or B--Cap-. The submitted B-Plan must demonstrate Equivalent Mass Emissions for included units cumulatively meets 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. The submitted B-Cap must be prepared using the calculation method provided in PR 1109.1 Attachment D to demonstrate that Equivalent Mass Emissions for included units cumulatively meets the Facility BARCT Emission Target less 10 percent and be adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6.

The plan approval will be contingent on including all of the required elements in the plans and the demonstration that the Percent Reduction Targets and Facility BARCT Emission Target will be met. If Executive Officer disapproves the initial I-Plan, B-Plan or B-Cap, the proposed rule considers a 30-day period for the owner or operator to resubmit a corrected plan. However, 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 pursuant to paragraph (f)(1) which requires permit applications to be submitted for all units to comply with PR 1109.1 Table 1 by July 1, 2023 and requires the operator to meet the NOx and CO limits 36 months after the Permit to Operate is issued. An operator who is required to meet the compliance schedule under paragraph (e)(1), is not precluded from meeting NOx and CO limits in Table 2, provided the requirements under paragraph (d)(6) for the conditional NOx and CO limits were met.

Modification to an Approved I-Plan, Approved B-Plan, or Approved B-Cap – Paragraph (i)(5)

Paragraph (i)(5) includes the procedure the facilities must following 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; or
- The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed.

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)(6)

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. that Executive Officer notify the public 30 days before announcing the approval of any initial or modified I-Plan, B-Plan or B-Cap for public review of the plans before they are approved or modifications are approved.

SUBDIVISIONS (j) AND (k) – REQUIREMENTS FOR CEMS AND SOURCE TESTING

These subdivisions contain the requirements for the combustion equipment subject to PR 1109.1 that required to continuously monitor emissions with CEMS or conduct the source test.

For any unit that has a CEMS or the operator elects to use a CEMS to demonstrate compliance with the applicable PR 1109.1 NOx and CO limits, the installation and operation of CEMS must be in compliance with the applicable Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications.

For any unit with no CEMS, compliance with the applicable PR 1109.1 NOx and CO emission 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, one for unit with no ammonia in the exhaust (e.g., units without SCR) and one schedule for units with ammonia in the exhaust. PR 1109.1 requires an owner or operator of a unit that has air pollution control equipment with ammonia emissions in the exhaust to demonstrate compliance with the established ammonia emission limit in the permit to operate. Compliance must be demonstrated with an ammonia CEMS or through conducting an ammonia source test. The source test schedules in Tables 6 or 7 vary depending on the use of CEMS for the different pollutants being measures (e.g., NOx, CO or ammonia). The schedule requires source tests be conducted on a quarterly basis during the first 12 months of unit operation and thereafter. The frequency may change to annually when four consecutive quarterly source tests demonstrate compliance with the applicable ammonia limit. The quarterly source test schedule is effective as soon as any annual test is failed to demonstrate compliance.

If a unit does not operate a certified NOx or CO CEMS, source test must be conducted simultaneously for ammonia, NOx and CO. Conducting a NOx, CO, and ammonia source test simultaneous is important as the pollutants have an inverse relationship and it is critical that both pollutants are meeting the limits.

Below are the source test schedules for units with and without ammonia in the exhaust:

Table 3-8. PR 1109.1 Table 7 – Source Testing Schedule Units without Ammonia Emissions in the Exhaust

Combustion Equipment	Source Test Schedule
Vapor Incinerators less than 40MMBtu/hr, Flares	• 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 CO and NOx limit. • 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 emission limit. • 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

Table 3-9. PR 1109.1 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 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 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 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 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.

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 permit limit and quarterly thereafter. • Source tests may be conducted annually after the first 12 months of being subject to an ammonia 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 for CO 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.

PR 1109.1 requires units that have not been source tested within the schedule in PR 1109.1 Table 7 or Table 8to conduct a source test within six months from the date the unit implements PR 1109.1 emission limits for units greater than or equal to 20 MMBtu/hour and within 12 months from the date the unit was subject to a PR 1109.1 emission limits for units smaller than 20 MMBtu/hour. For a new or modified unit, the initial source test must be conducted within six months from commencing operation and afterward, pursuant to the applicable schedule in PR 1109.1 Table 7 or Table 8.

PR 1109.1 requires the owner or operator to submit the source test protocol, that includes an averaging time of no less than 15 minutes but no longer than 2 hours, to the South Coast AQMD Executive Officer for approval within 60 days after the Permit to Construct was issued or 60 days after being subject to a Rule 1109.1 Emission limit, unless otherwise approved by the Executive Officer and conduct the source test within 90 days after a written approval of the source test protocol. Moreover, the owner or operator must notify the Executive Officer at least one week prior to conducting a source test and provide the facility name and identification number, device identification number, and the source test date. Any source test conducted after the approval of the initial source test protocol does not require an approval if there is no change in the proposed rule or permit emission limits and the method of operation of the unit and the source test method has not changed since the initial source test, unless requested by the Executive Officer.

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, using the applicable Averaging Time specified in Table 1 and based on at least one of the following 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 – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);
- District Source Test Method 207.1 – Determination of Ammonia Emissions from Stationary Sources; or
- Any other test method determined to be alternative and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

The source test subdivision also includes the required averaging time for units that are required to demonstrate compliance with a PR 1109.1 emission limits based on a source test. All units that are not required to install and maintain CEMs must demonstrate compliance based on a 2-hour source test protocol.

SUBDIVISION (l) – 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 diagnostic checks and the applicable schedule based on the corresponding source test schedule identified in Table 7 of PR 1109.1.

If emissions are measured in excess of an applicable PR 1109.1 emission limit or a permit condition using a diagnostic emissions check, 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 (m) – 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.

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.

SUBDIVISION (n) – 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 rated heat input capacity 2 MMBtu/hour or less – Paragraph (n)(1)

Small boilers and process heaters (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 (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 (n)(2)

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

Low-Use Process Heaters – Paragraph (n)(3)

Low-use process heaters that are 40 MMBtu/hour or greater and fired at less than 15 percent of the rated heat capacity are exempt from the emission limits in Table 1, Table 2, or an approved B-Plan. 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 and must be included in an approved B-Cap and the interim emission limits.

FCCU exemption provisions – Paragraphs (n)(4) and (n)(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 200 hours or less per calendar year. Facilities that elect to comply with a B-Cap must include such process heater in the approved B-Cap and conduct source tests pursuant to Rule 1109.1 Table 7 or 8 and conduct diagnostic emission checks. The unit will have to accept a permit limit with a 200 hour per year operating limitation.

Startup and Shutdown Boilers for Sulfuric Acid Plants– Paragraph (n)(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 and the CEMS requirements 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.

Pilot Exemption for Boilers and Process Heaters – Paragraph (n)(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 (n)(8)

Non-refinery flares that emit less than or equal to 550 pounds of NOx per 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 (n)(9)

Vapor incinerators also have a low-emitting exemption if they emit less than 100 pounds of NOx per year. These units are not cost effective to control or replace at this time.

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 3-10. 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 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 3-11. 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 Limit (ppmv)	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	[illegible]	16.6	7.5	24.9
D3	D3	SMR Heater	450	97	[illegible]	[illegible]	[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	[illegible]	[illegible]	[illegible]	[illegible]	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 3-12. 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]	[illegible] Eligible, Red > 20 TPY
D4	D4	FCCU		83	11	2.0	[illegible]	[illegible]	[illegible]	Possibly Eligible
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Possibly 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	Possibly Eligible
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Possibly Eligible
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Possibly 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	Possibly 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

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 table below shows the owner final selection of NOx limits for the units and the corresponding Final Phase Facility BARCT Emission.

As shown in the table 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. For this example, the Final BARCT Emission Target is 175.7 tons per year.

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 3-13. 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 [illegible] 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	Possibly Eligible	Table 2	60.4
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Possibly 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	Possibly Eligible	[illegible]	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Possibly Eligible	Table 1	5.5
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Possibly 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	Possibly Eligible	Table 2	2.8
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	**175.7**

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

NOx emissions based on Table selection
Cannot select Table 2, if "Not Eligible"

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:

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

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 554.3 tons/year (730 tons/year-175.7 tons/year).

Table 3-14. 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	Possibly Eligible	Table 2	60.4
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Possibly 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	Possibly Eligible	Table 2	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Possibly Eligible	Table 1	5.5
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Possibly 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	Possibly Eligible	Table 2	2.8
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**								**175.7**

Total Facility NOx Emission Reductions
730 tons/year - 175.7 tons/year = 554.3 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:

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

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:

$$\textbf{Phase I Facility BARCT Emission Target}_{\textbf{B-Plan}} = \mathbf{730 - (554.3 \times 0.7) = 342.0\ tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Plan}} = \mathbf{730 - (554.3 \times 1.0) = 175.7\ tons/year}$$

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 3-15. 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	Possibly Eligible	[illegible]	7.0	52.8	7.0	52.8
D5	D5	Heater	290	54	18	Possibly 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	[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	Possibly Eligible	N/A	18.0	9.6	[illegible]	[illegible]
D10	D10	Boiler	330	11	10	Possibly Eligible	N/A	10.0	11.0	[illegible]	[illegible]
D11	D11 and D12	Heater	75	8	16	Possibly 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	Possibly 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 Emission Limit

The operator must calculate the BARCT Equivalent Mass Emissions for each phase of the I-Plan. The Phase I BARCT Equivalent Mass Emissions for the B-Plan equation is shown below. Phase

II and Phase III BARCT Equivalent Mass Emissions are calculated with the same equation but using the Alternative BARCT Emission Limit for the applicable phase.

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

Where:

N	=	Number of included units 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 3-16. 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	Possibly Eligible	N/A	7.0	52.8	7.0	52.8
D5	D5	Heater	290	54	18	Possibly 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	Possibly Eligible	N/A	18.0	9.6	18.0	9.6
D10	D10	Boiler	330	11	10	Possibly Eligible	N/A	10.0	11.0	8.0	8.8
D11	D11 and D12	Heater	75	8	16	Possibly 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	20.0	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	Possibly 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	**342.0**		**175.7**

B-Cap

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 reduced by 10 percent. This is a 10 percent environmental benefit to meet U.S. EPA requirements for Economic Incentive Programs. Under this example, I-Plan Option 4 is used. If a unit is list 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 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." Under this 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 of the conditions under subparagraph (d)(2)(A) and have a representative NOx concentration at or below 25 ppmv. The equation below provides how the Facility BARCT Emission Target is established for each Phase of the B-Cap:

$$\begin{aligned}\text{Each Phase Facility BARCT Emission Target}_{\text{B-CAP}} &= [\text{Baseline Emissions} \\ &- (\text{Each Phase Percent Reduction Target} \\ &\times \text{Total Facility NOx Emission Reductions})] \times 0.9\end{aligned}$$

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

For I-Plan Option 4, the Phase I, Phase II and Phase III Facility BARCT Emission Target calculations will be as follows:

$$\textbf{Phase I Facility BARCT Emission Target}_{\textbf{B-Cap}} = (\mathbf{730} - (\mathbf{554.3} \times \mathbf{0.5})) \times \mathbf{0.9} = \mathbf{407.6}\ \textbf{tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Cap}} = (\mathbf{730} - (\mathbf{554.3} \times \mathbf{0.8})) \times \mathbf{0.9} = \mathbf{257.9}\ \textbf{tons/year}$$

Phase II Facility BARCT Emission Target$_{\mathbf{B-Cap}} = \mathbf{(730 - (554.3 \times 1.0)) \times 0.9 = 158.1}$ **tons/year**

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

After the Phase I and Phase II Facility BARCT Emission Targets are established, the operator then calculates the BARCT Equivalent Mass Emissions. For the B-Cap, the emissions are based on the concentration limits, emission reductions from decommissioned units, and emission reductions from throughput or any other emission reductions. As shown in the table below, the operator selects the Phase I Alternative BARCT Emission Limit for each unit and any decommissioned units. The BARCT Facility Emission Target must be based on Table 1 NOx limits for any decommissioned unit. For the B-Cap, the Phase I BARCT Equivalent Mass Emissions 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 378.0 tons/year, the Phase II BARCT Equivalent Emissions are 228.6 tons/year and the Phase III BARCT Equivalent Emissions are 153.7 tons/year.

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

Device ID	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	245	100	[illegible]	Yes	0.0	0.0	0.0	[illegible]	[illegible]	0.0	0.0	0.0	0.0
D2	126	38	Not Eligible, Red > 20 TPY	No	20.0	66.3	50.0	[illegible]	[illegible]	50.0	10.0	33.2	33.2
D3	97	48	Not Eligible, Red > 20 TPY	No	48.0	97.0	80.0	[illegible]	[illegible]	20.2	10.0	20.2	20.2
D4	83	11	Possibly Elig[illegible]	[illegible]	11.0	83.0	83.0	[illegible]	[illegible]	52.8	7.0	52.8	30.0
D5	54	18	Possibly Elig[illegible]	[illegible]	18.0	54.0	40.0	[illegible]	[illegible]	18.0	6.0	18.0	18.0
D6	29	33	Not Eligible, Red [illegible]	[illegible]	33.0	29.0	29.0	[illegible]	[illegible]	5.3	6.0	5.3	5.3
D7	24	65	Not Eligible, Red [illegible]	[illegible]	65.0	24.0	24.0	[illegible]	[illegible]	24.0	4.0	1.5	1.5
D8	14	48	Not Eligible, Red [illegible]	[illegible]	48.0	14.0	14.0	[illegible]	[illegible]	2.6	4.0	1.2	1.2
D9	12	22	Possibly Eligible	No	22.4	12.0	12.0	18.0	9.6	9.6	18.0	9.6	9.6
D10	11	10	Possibly Eligible	No	10.0	11.0	11.0	10.0	11.0	11.0	8.0	8.8	8.8
D11	8	16	Possibly Eligible	No	16.0	8.0	8.0	12.0	6.0	6.0	12.0	6.0	6.0
D12	8	16	Eligible	No	16.0	8.0	8.0	20.0	10.0	10.0	20.0	10.0	10.0
D13	3	8	Eligible	No	8.0	3.0	3.0	8.0	3.0	3.0	8.0	3.0	3.0
D14	3	43	Possibly Eligible	[illegible]	[illegible]	[illegible]	3.0	43.0	3.0	3.0	10.0	0.7	0.7
D15	3	12	No Table 2 Limit	[illegible]	[illegible]	[illegible]	3.0	12.0	3.1	3.1	9.0	2.3	2.3
D16	10	35	No Table 2 Limit	[illegible]	[illegible]	[illegible]	10.0	35.0	10.0	10.0	14.0	4.0	4.0
Baseline Facility Emissions	**730**						**378.0**			**228.6**			**153.7**

Unit will be decommissioned

Operator selects Alternative BARCT Emission Limit for Each Unit

Phase I BARCT B-Cap Annual Emissions are the sum of the mass emission for each unit using the Alternative BARCT Emission Limit

Phase I BARCT Equivalent Emissions include emissions from Alternative BARCT Emission Limits, decommissioned units, and througput and other

The operator must calculate the BARCT B-Cap Annual Emissions for each phase of the I-Plan. The Phase I BARCT B-Cap Annual Emissions for the B-Cap equation is shown below. Phase II and Phase III BARCT B-Cap Annual Emissions are calculated with the same equation but using the Alternative BARCT Emission Limits for the applicable phase and additional emission reduction strategies to reduce mass emissions.

$$\text{Phase I BARCT Equivalent Mass Emissions}_{\text{B-Cap}} = \sum_{i=1}^{N}\left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})$$

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 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 reducing the concentration limit.

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 378.0 tons/year which are less than the Phase I Facility BARCT Emission Target of 407.6 tons/year; the Phase II BARCT Equivalent Mass Emissions are 228.6 tons/year which are less than the Phase II Facility BARCT Emission Target of 257.9 tons/year; and the Phase III BARCT B-Cap Annual Emissions are 153.7 tons/year which are less than the Phase III Facility BARCT Emission Target of 158.1 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 3-18. Demonstrating the B-Cap Will Achieve the Facility BARCT Emission Targets

Device ID	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 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	245	100	Not Eligible, Red > 20 TPY	Yes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
D2	126	38	Not Eligible, Red > 20 TPY	No	20.0	66.3	50.0	20.0	66.3	50.0	10.0	33.2	33.2
D3	97	48	Not Eligible, Red > 20 TPY	No	48.0	97.0	80.0	10.0	20.2	20.2	10.0	20.2	20.2
D4	83	11	Possibly Eligible	No	11.0	83.0	83.0	7.0	52.8	52.8	7.0	52.8	30.0
D5	54	18	Possibly Eligible	No	18.0	54.0	40.0	6.0	18.0	18.0	6.0	18.0	18.0
D6	29	33	Not Eligible, Red > 20 TPY	No	33.0	29.0	29.0	6.0	5.3	5.3	6.0	5.3	5.3
D7	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	14	48	Not Eligible, Red > 10 TPY	No	48.0	14.0	14.0	9.0	2.6	2.6	4.0	1.2	1.2
D9	12	22	Possibly Eligible	No	22.4	12.0	12.0	18.0	9.6	9.6	18.0	9.6	9.6
D10	11	10	Possibly Eligible	No	10.0	11.0	11.0	10.0	11.0	11.0	8.0	8.8	8.8
D11	8	16	Possibly Eligible	No	16.0	8.0	8.0	12.0	6.0	6.0	12.0	6.0	6.0
D12	8	16	Eligible	No	16.0	8.0	8.0	20.0	10.0	10.0	20.0	10.0	10.0
D13	3	8	Eligible	No	8.0	3.0	3.0	8.0	3.0	3.0	8.0	3.0	3.0
D14	3	43	Possibly Eligible	No	43.0	3.0	3.0	43.0	3.0	3.0	10.0	0.7	0.7
D15	3	12	No Table 2 Limit	No	11.7	3.0	3.0	12.0	3.1	3.1	9.0	2.3	2.3
D16	10	35	No Table 2 Limit	No	35.0	10.0	10.0	35.0	10.0	10.0	14.0	4.0	4.0
Baseline Facility Emissions	**730**						**378.0** ✔			**228.6** ✔			**153.7** ✔
						Facility BARCT Emission Targets	**407.6**			**257.9**			**158.1**

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

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 3-19. PR 1109.1 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

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

Table 3-20. PR 1109.1 Table D-1 – Units 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

Table 3-21. PR 1109.1 Table D-2 – Units 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

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.

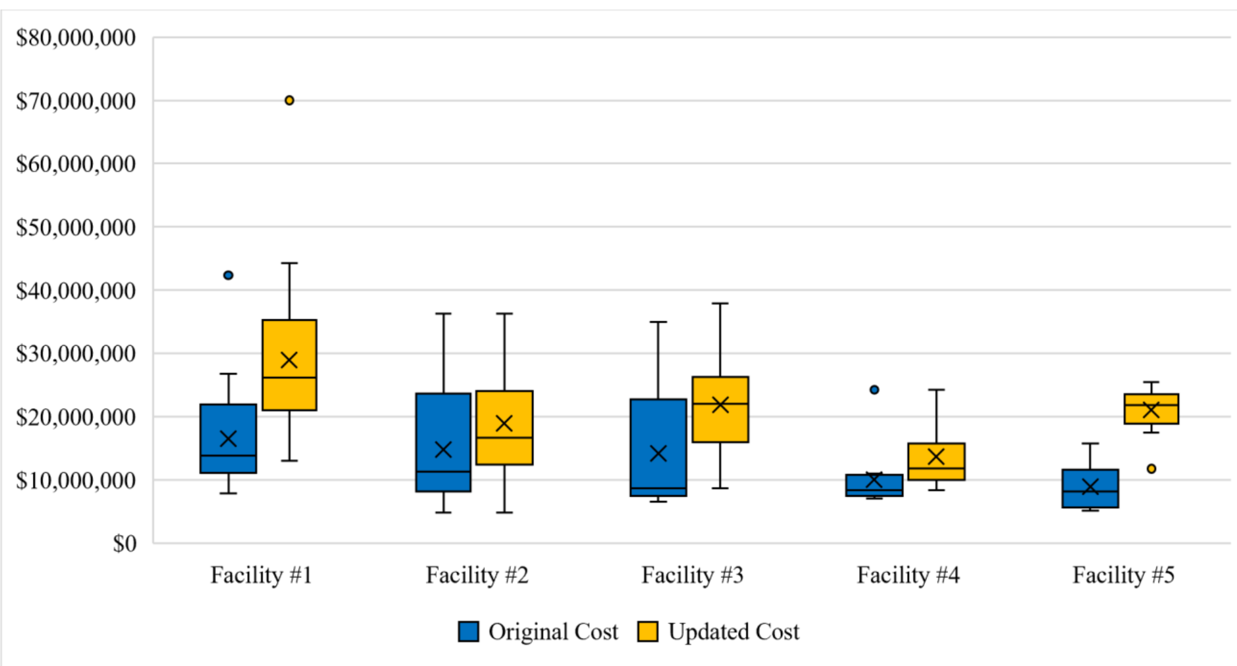


Figure 4-1. Original and updated cost provided by facilities

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.

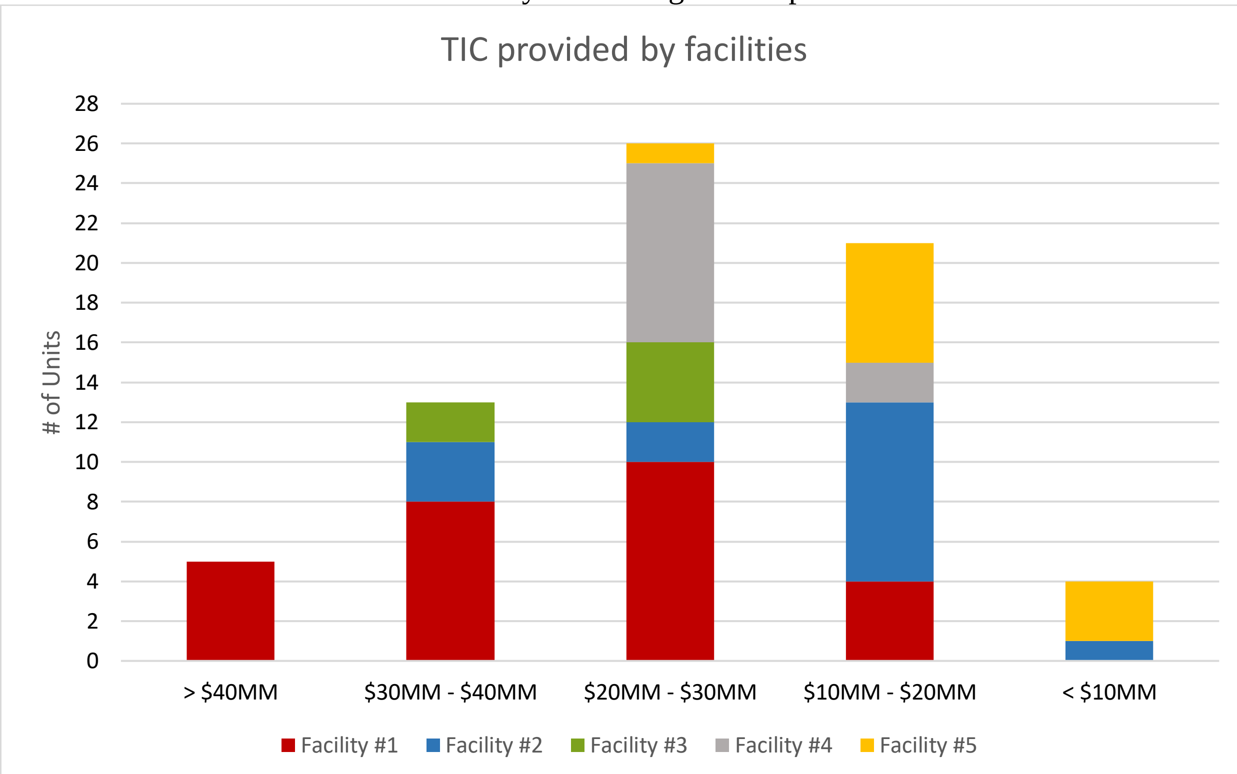


Figure 4-2. The number and range of control costs for each facility in the second survey

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 12.3 tons per day based on a 2017 baseline. After the adoption of PR1109.1, the emissions are estimated to be reduced between 6.5 to 8 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	5.03	3.4
Boilers	2.56	2.2
Gas Turbine	1.44	0.4
SMR Heaters	1.10	0.6
FCCU	0.83	0.4
Coke Calciner	0.71	0.7
SRU/TG Incinerator	0.43	0.1
Sulfuric Acid Plants	0.1	0.0
Vapor Incinerators	0.05	0.02
Total	12.3	7.8

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 NEC and FERCo to address annual SCR tuning and increased catalyst volume. Detailed cost information can be found in the appendix for use 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 NEC 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 6.5 to 8 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 the appendices.

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)	$50,000	$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)

Equipment Category	Cost Effectiveness	
	DCF	LCF
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.

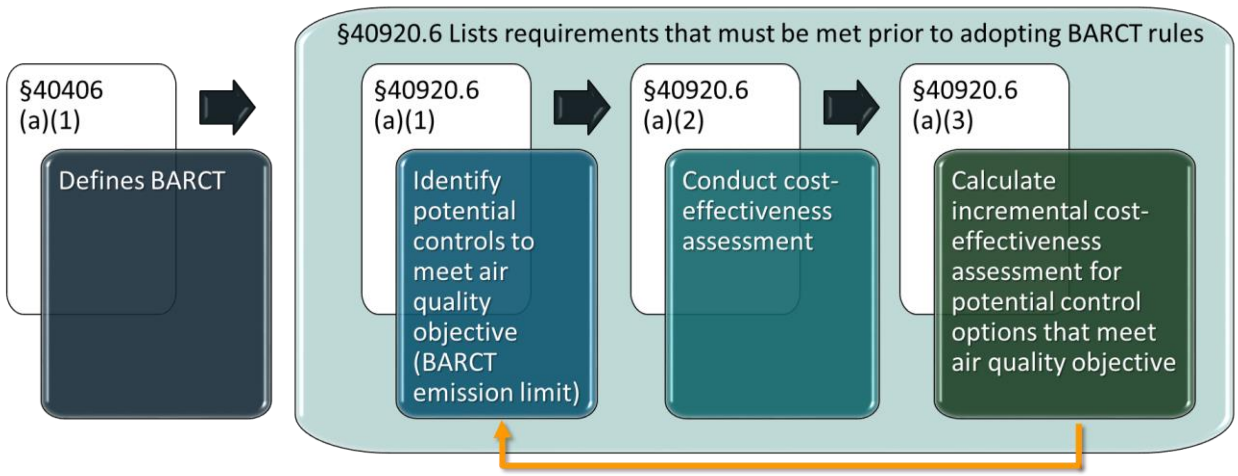


Figure 4-3. California Health and Safety Code Section BARCT Requirements

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.

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

A Draft Socioeconomic Impact Assessment is being prepared and state law requires that assessment be released at least 30 days prior to the South Coast AQMD Governing Board Hearing on PR 1109.1, which is anticipated to be heard on November 5, 2021. However, due to the high interest in this project and comprehensiveness of the analysis, staff is considering a longer 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 is preparing 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 will contain the environmental analysis required by CEQA Guidelines Section 15187 and will tier 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 will be 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. A comparative analysis will be prepared and released at least 30 days prior to the South Coast AQMD Governing Board Hearing on PR 1109.1, which is anticipated to be heard on November 5, 2021.

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 are 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.

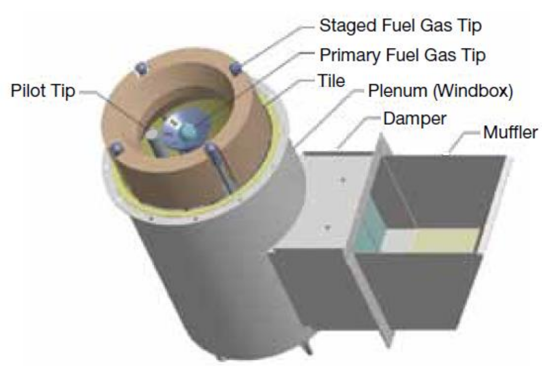


Figure A-1. Low NOx Burner Design

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.

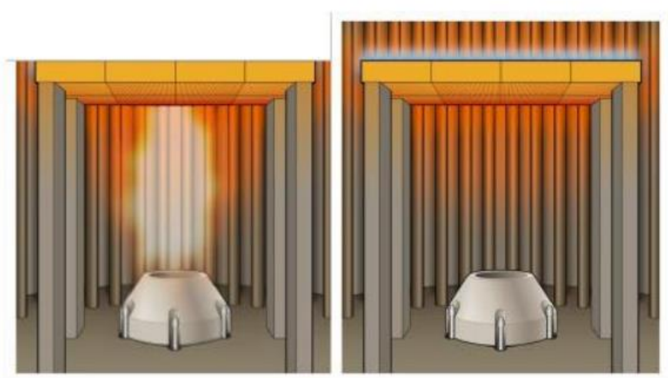


Figure A-2. Conventional burner heating up a DUPLEX tile

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.

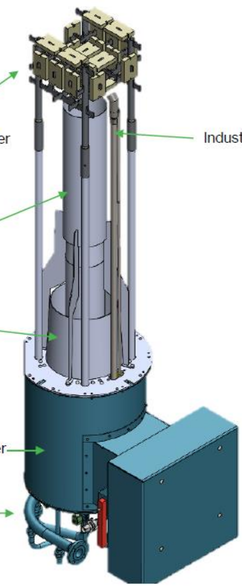


Figure A-3. ClearSign Core Process Burner

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. 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 between 5 and 9 ppmv. With further tuning and refinement, 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.

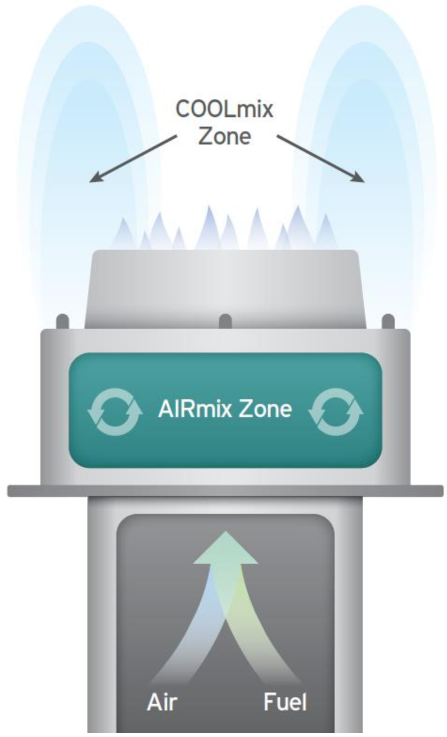


Figure A-4. John Zink SOLEX™ Burner

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.

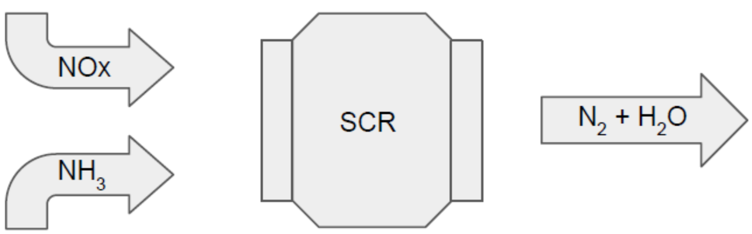


Figure A-5. NOx Reductions in SCR

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

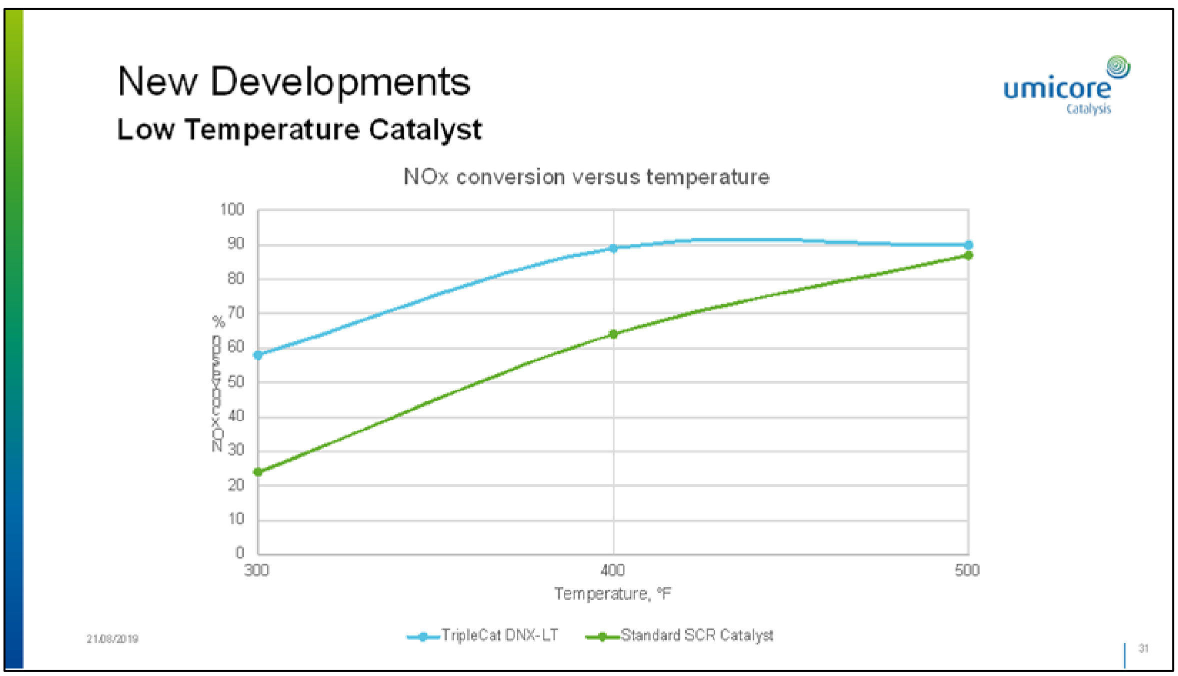


Figure A-6. Umicore's TripleCat DNX-LT

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.

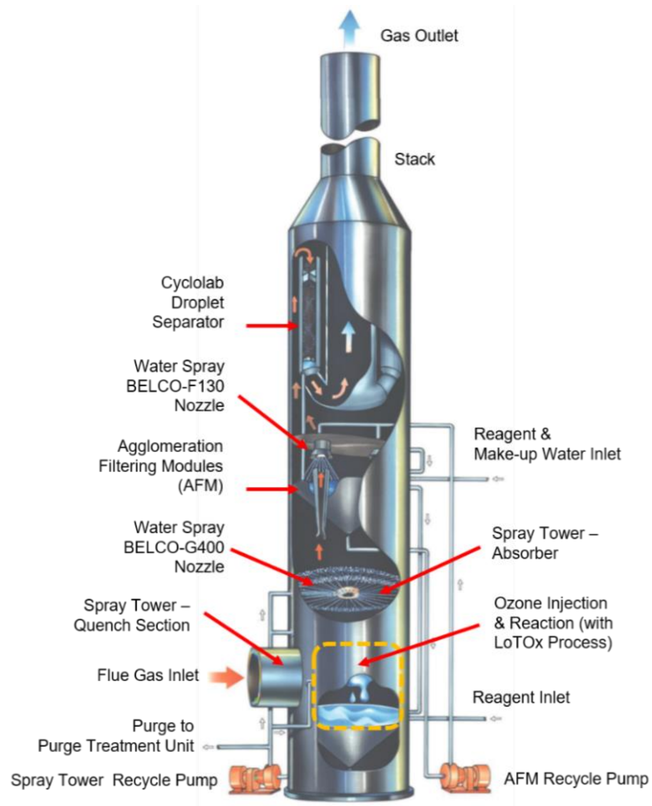


Figure A-7. EDV® Scrubber with LoTOx™ NOx Control[3]

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.

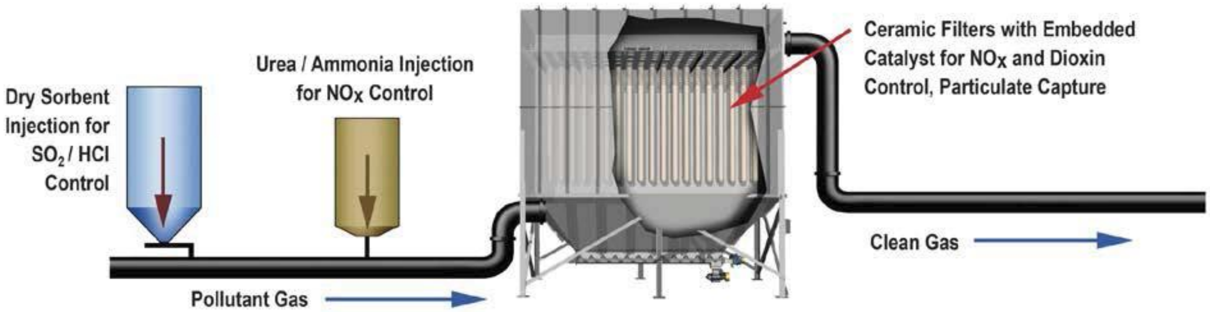


Figure A-8. UltraCat Filters

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.

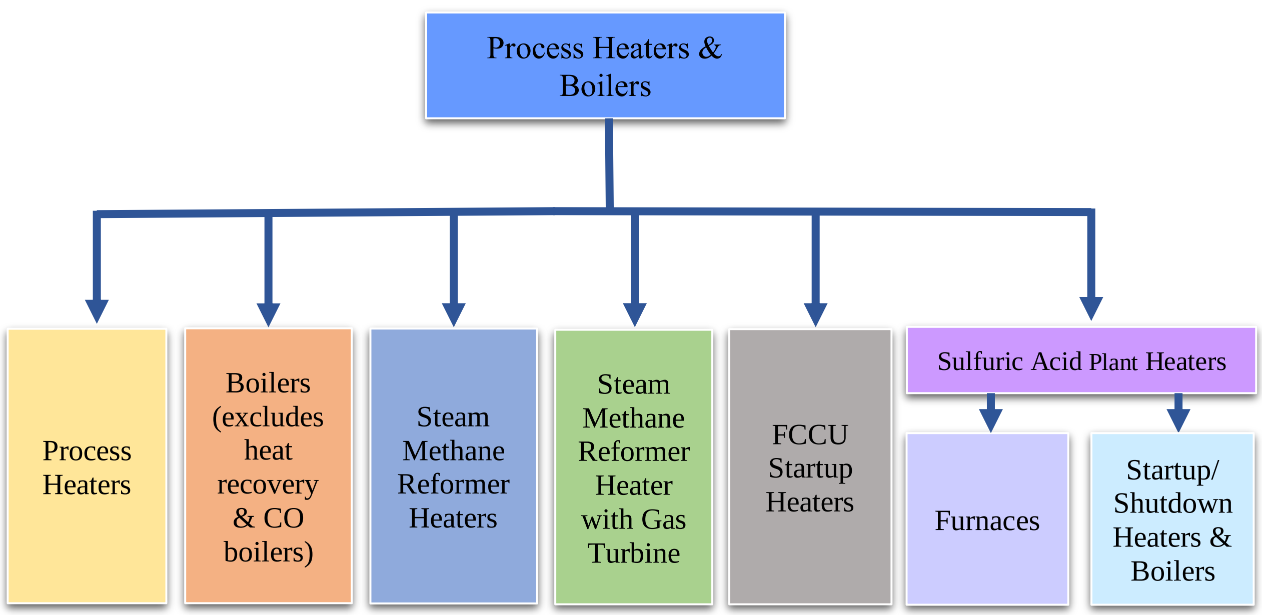


Figure B-1. Six major sub-categories of Boilers & Process Heaters Category

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 direct-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.

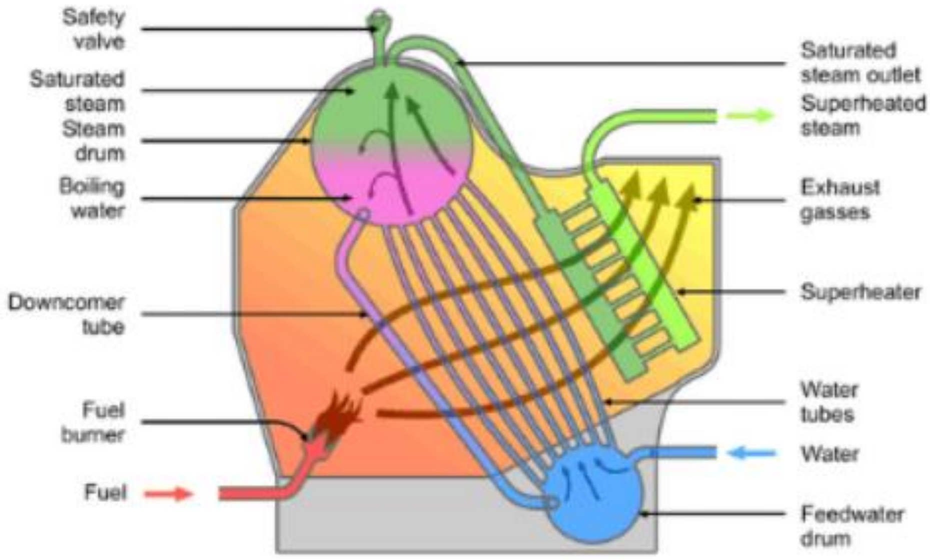


Figure B-2. Water Tube Boiler

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 are 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.

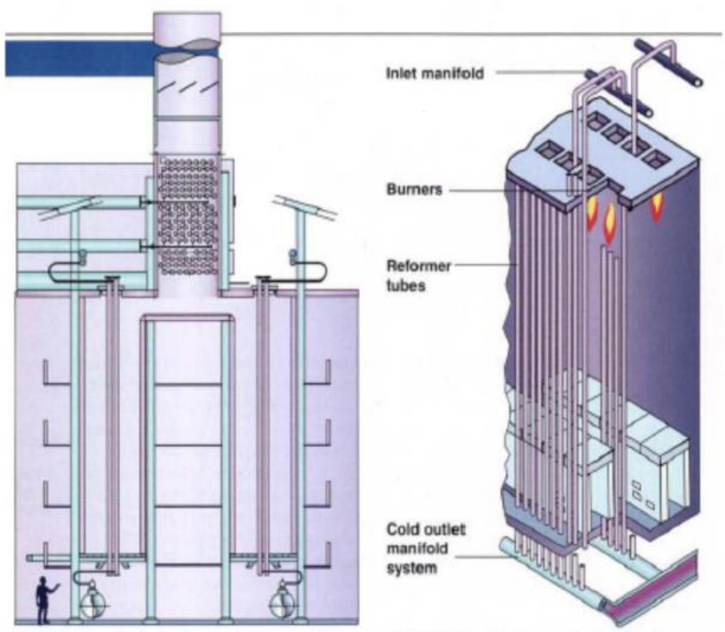


Figure B-3. Typical reformer heater designs can potentially have over 300 burners. All are greater than 110 MMBtu/hr in size

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 consist 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 permit limit. In contrast, most units rated less than 40 MMBtu/hr have 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 40 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 is 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 is 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.

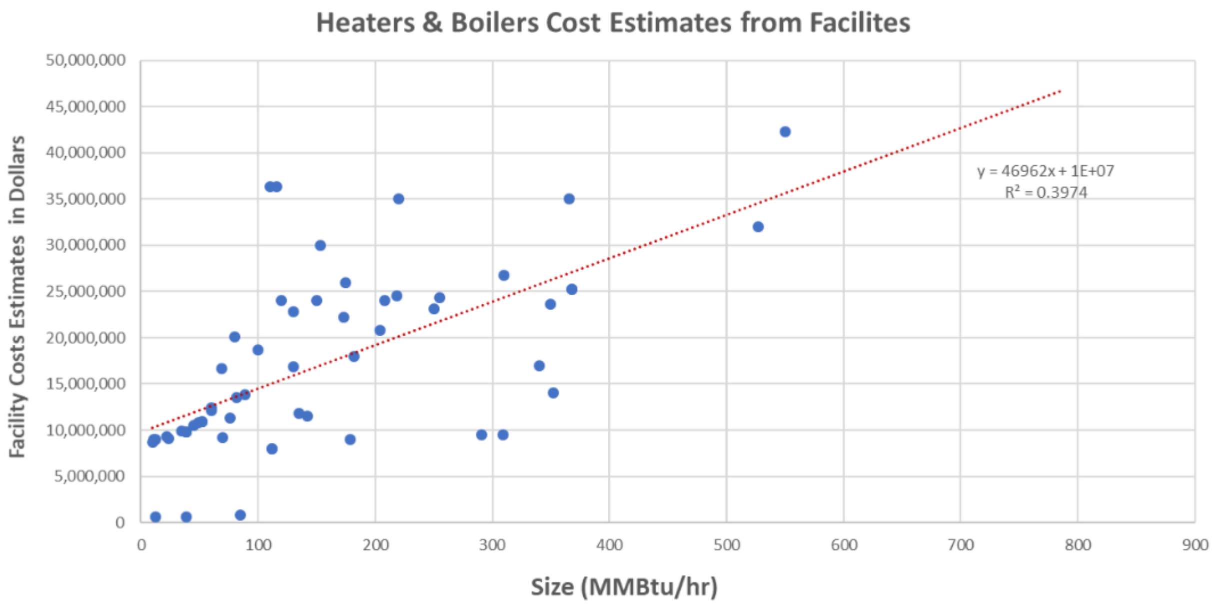


Figure B-4. SCR TIC costs provided by facilities versus corresponding heater/boiler sizes

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 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 cost for units where costs were not submitted 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 SCR cost model that was used to estimate cost for SCR projects at refineries.

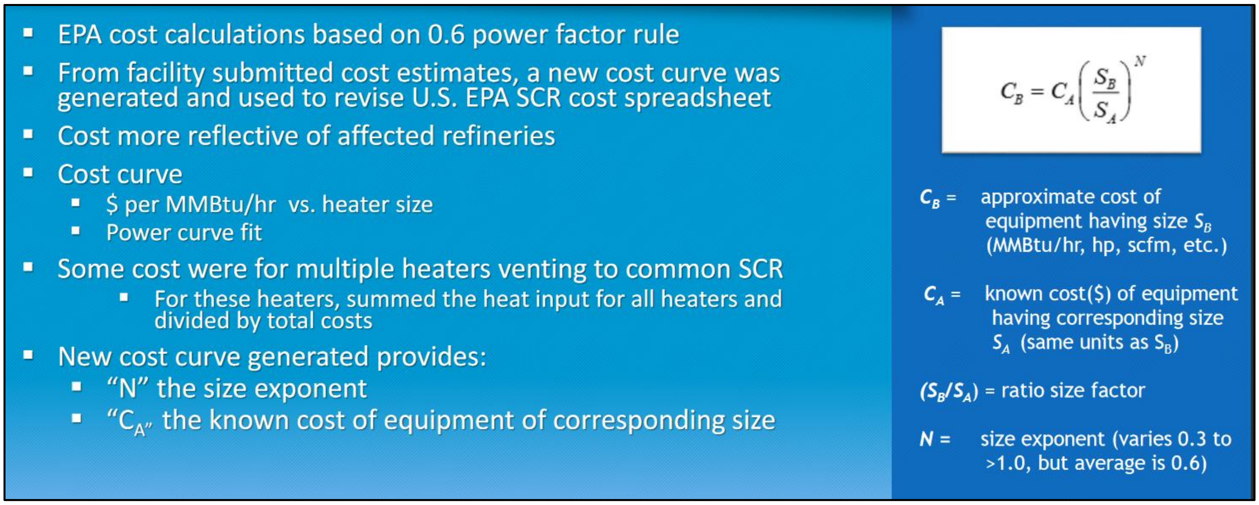


Figure B-5. Rule of Six-tenths (0.6 Power Factor Rule)

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 constructions phase – these were detailed estimates. And provided an indication of a typical SCR project cost. However, majority of the cost were a mixture of project scope or order of magnitude cost but based on NEC's review of the cost data considered the cost data 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.

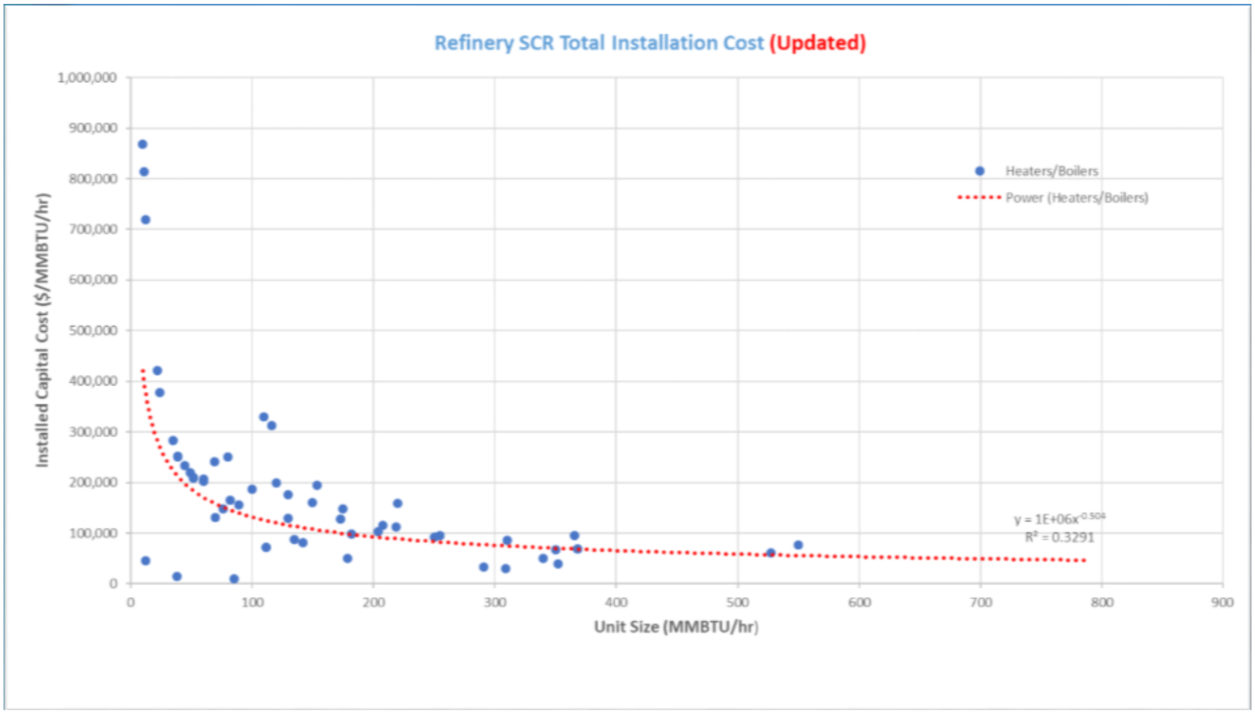


Figure B-6. Cost curve used to revise U.S. EPA SCR cost spreadsheet

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.

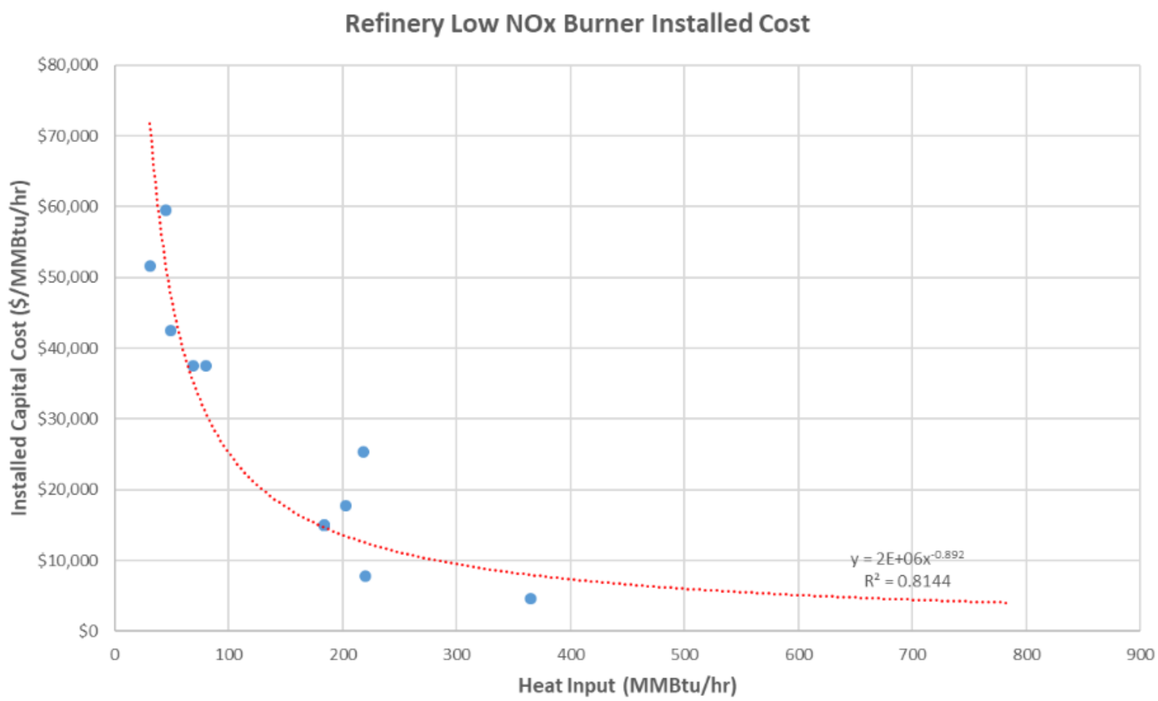


Figure B-7. LNB/ULNB Cost-Curve Used to Estimate Burner TIC For Boilers And Process Heaters

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 NEC, 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 NEC's suggestion. Staff updated the cost-effectiveness for SMR category based on the new cost estimates.

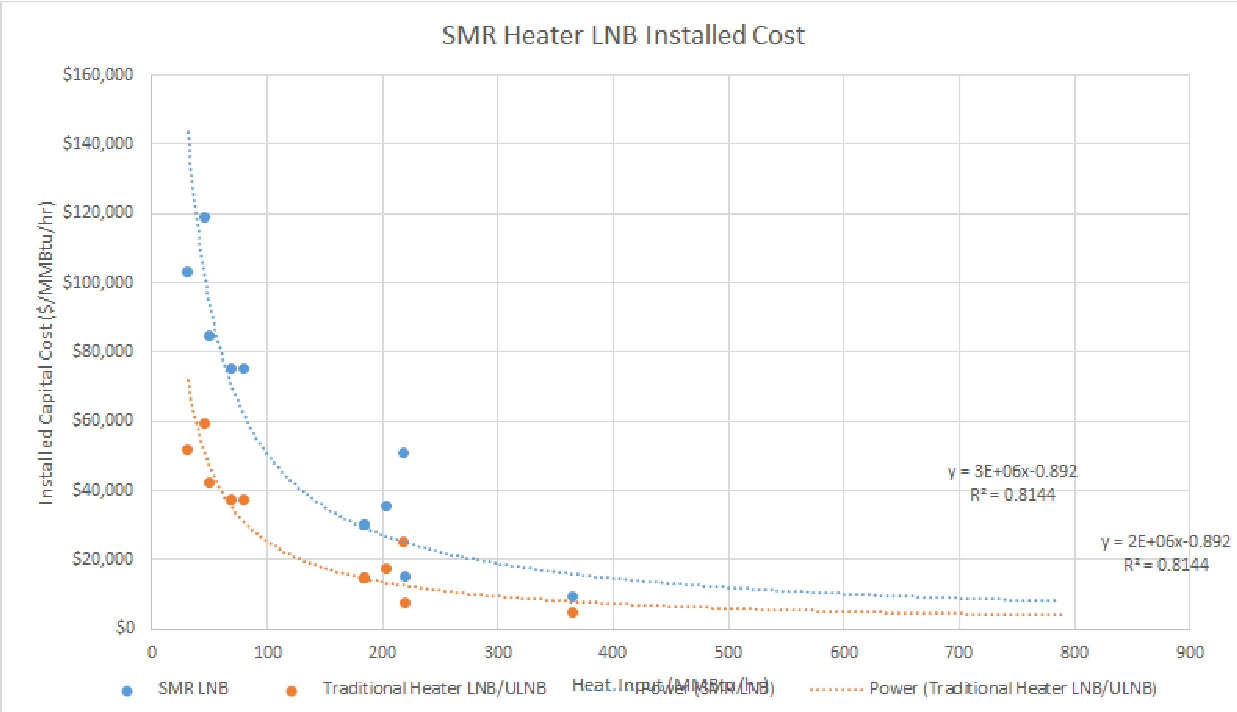


Figure B-8. LNB cost curve for SMR heaters versus traditional heaters

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 all units less than 40 MMBtu/hr are currently performing at or have permit limits near 40 ppmv. However, staff also 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. However, process heaters and boiler larger than or equal to 40 MMBtu/hr were cost-effective to go to 2 ppmv, so staff proposed a BARCT limit of 2 ppmv for the large process heater and boiler category based on a combination control technology that utilize both ULNB and SCR.

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 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 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 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:

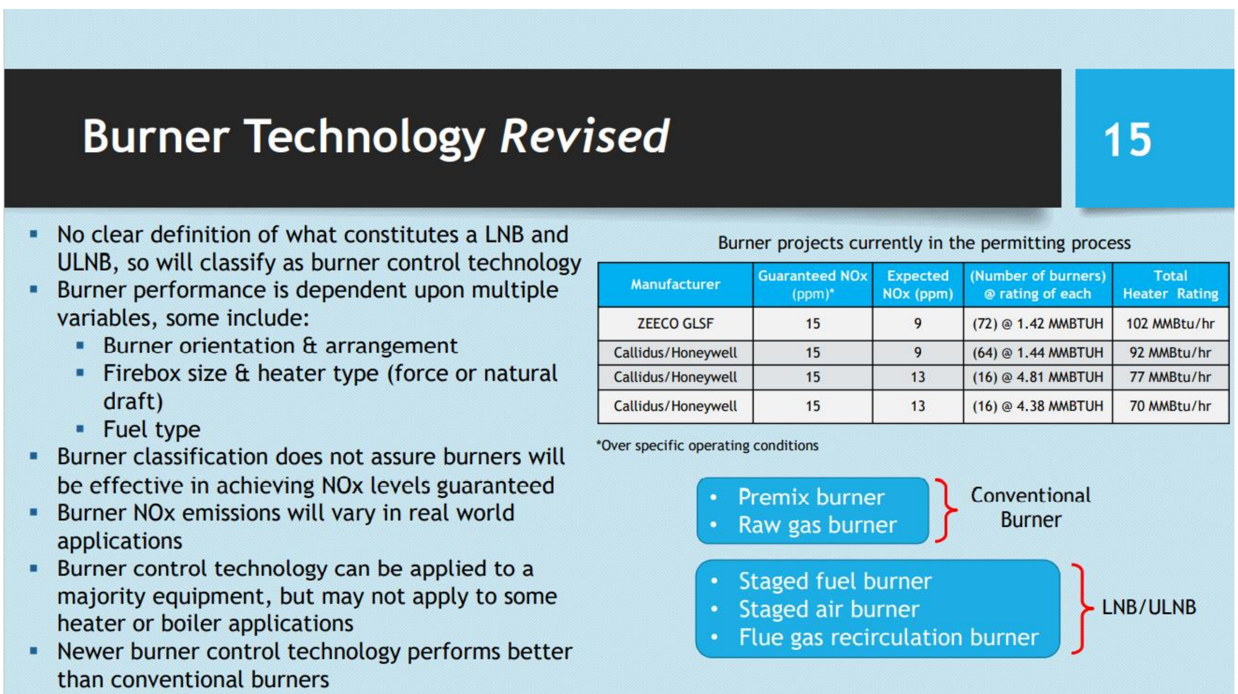


Figure B-9. Slide from Working Group #6

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, 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-11. Slide 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
Increased 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-12. Cost-Effectiveness Reassessment Using Dual Stage Reactor

Equipment Class	NOx Limit	ULNB/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 will modify the BACRT analysis to integrate the incremental cost-effectiveness.

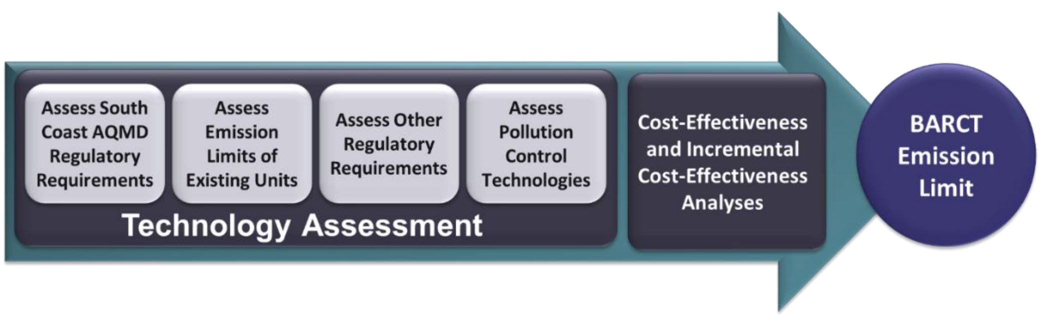
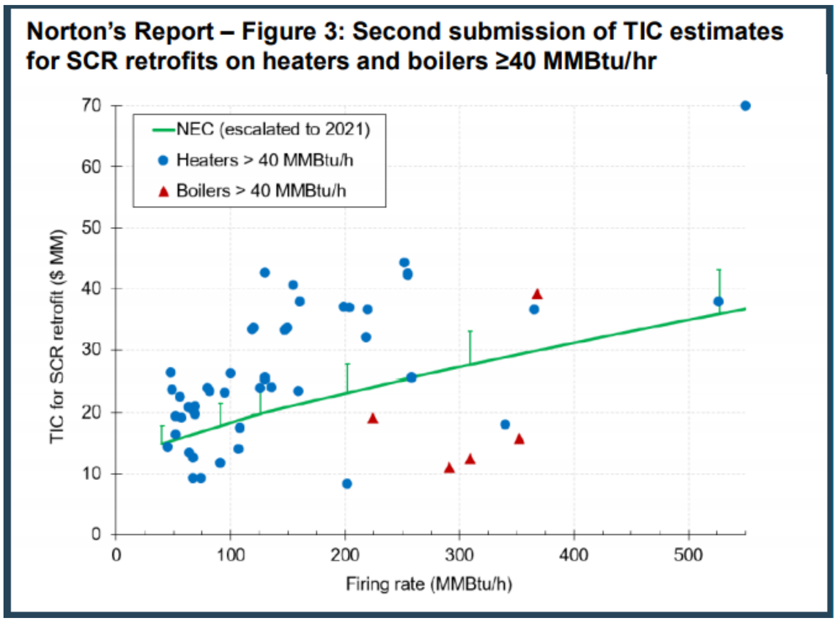


Figure B-10. BARCT Assessment Approach

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.

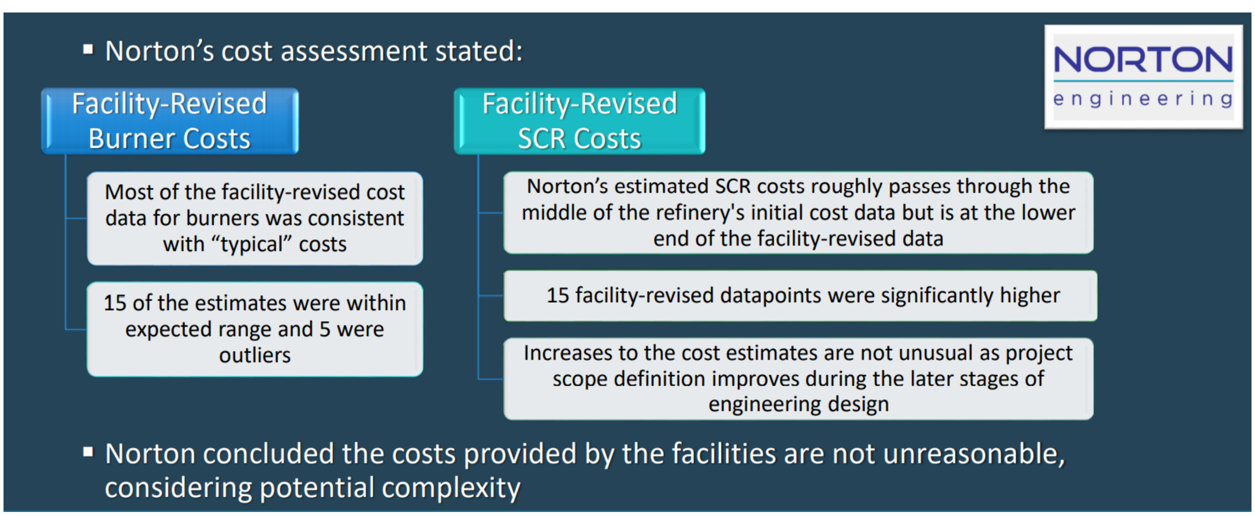
As part of the revised cost, staff requested the assistance of Norton Engineering for review of the cost data and provided the following comparisons:

- Revised burner costs were compared against a "typical" cost curve for burner upgrades
- Refinery's initial cost data compared to Norton's escalated cost estimates from the 2014 NOx RECLAIM BARCT feasibility study
- Refinery's revised cost data compared to Norton'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

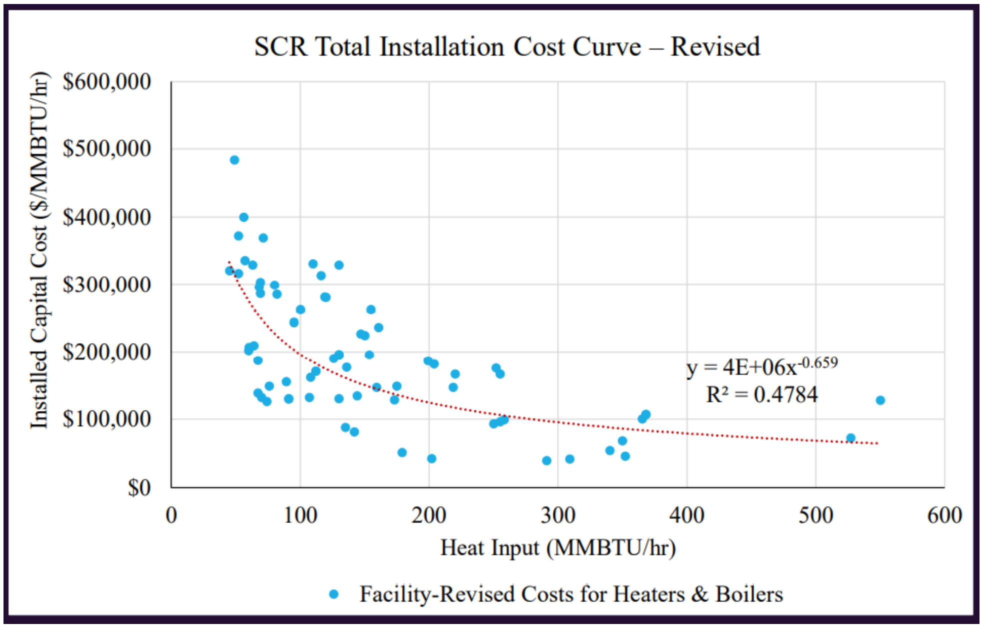


Norton's Report – Figure 3: Second submission of TIC estimates for SCR retrofits on heaters and boilers ≥40 MMBtu/hr

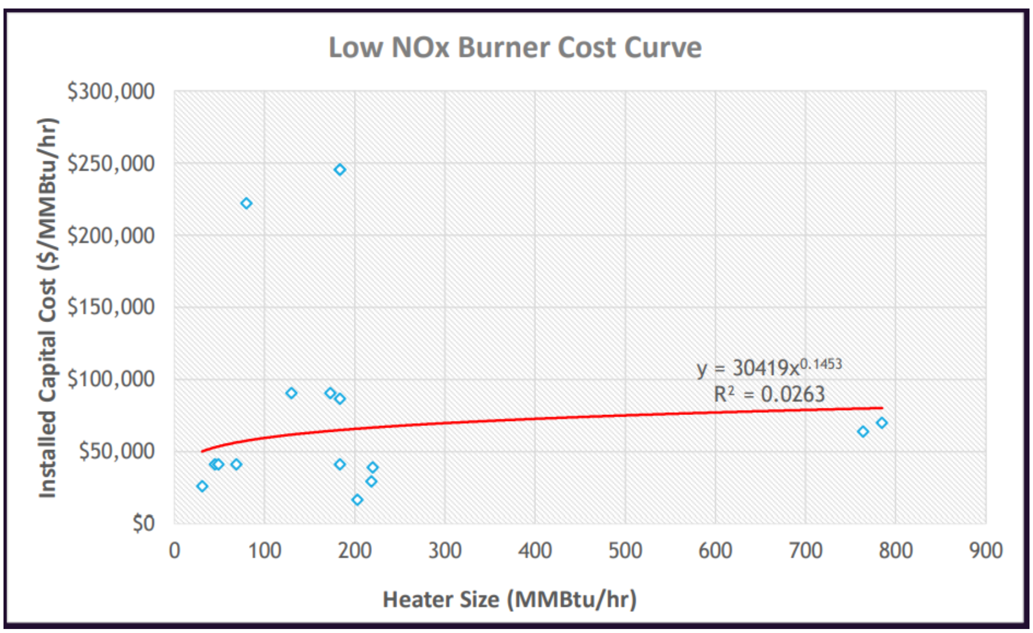
Norton Engineering's review and feedback regarding the facility revised cost data was presented in Working Group Meeting #22 on June 30, 2021. Norton Engineering's conclusion was that the costs provided by the facilities are not unreasonable, considering the potential complexity.



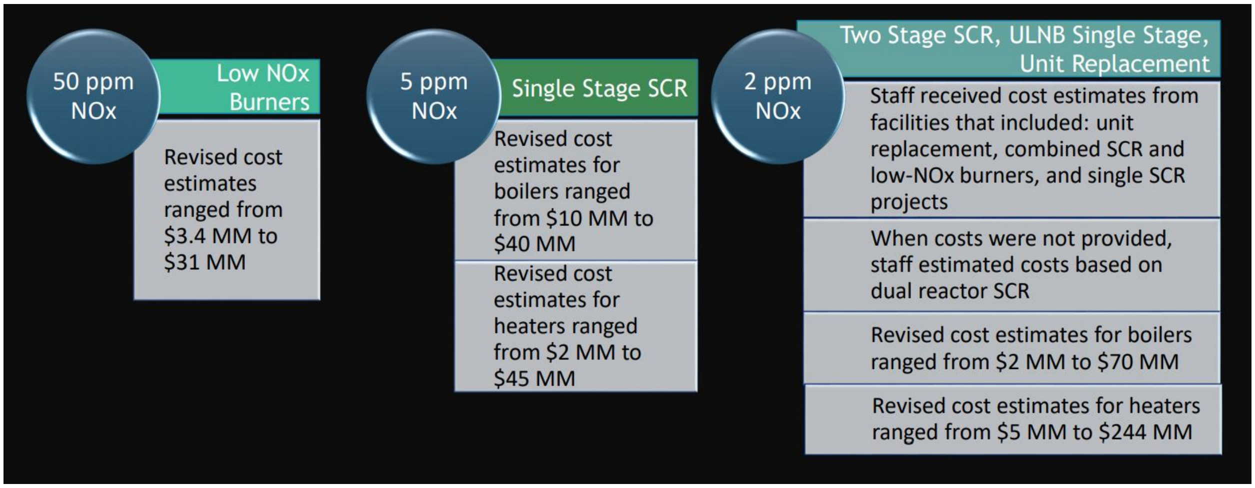
Based on Norton's recommendation, staff used all revised cost data submitted by facilities. Like the initial BARCT assessment, if cost for a specific device was provided, staff will use that cost in BARCT reassessment. In order to estimate costs for devices where costs were not provided, staff used all facility-revised data to update the power curve that will be used in U.S. EPA SCR cost model.



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.

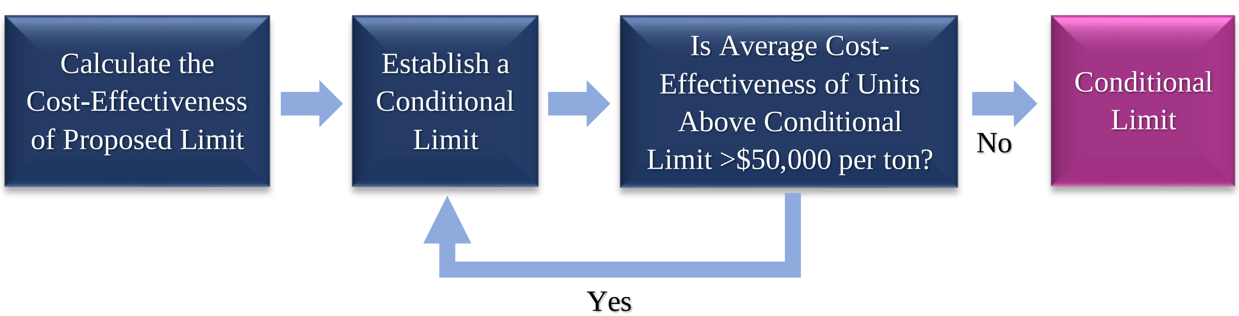


Once the cost estimate methodology has been updated, staff proceeded with the BARCT reassessment for the process heater and boiler category. Norton Engineering's final report concluded that sub-optimal burner conditions within a process heater will achieve 40 to 50 ppmv – this will be used to updates 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:



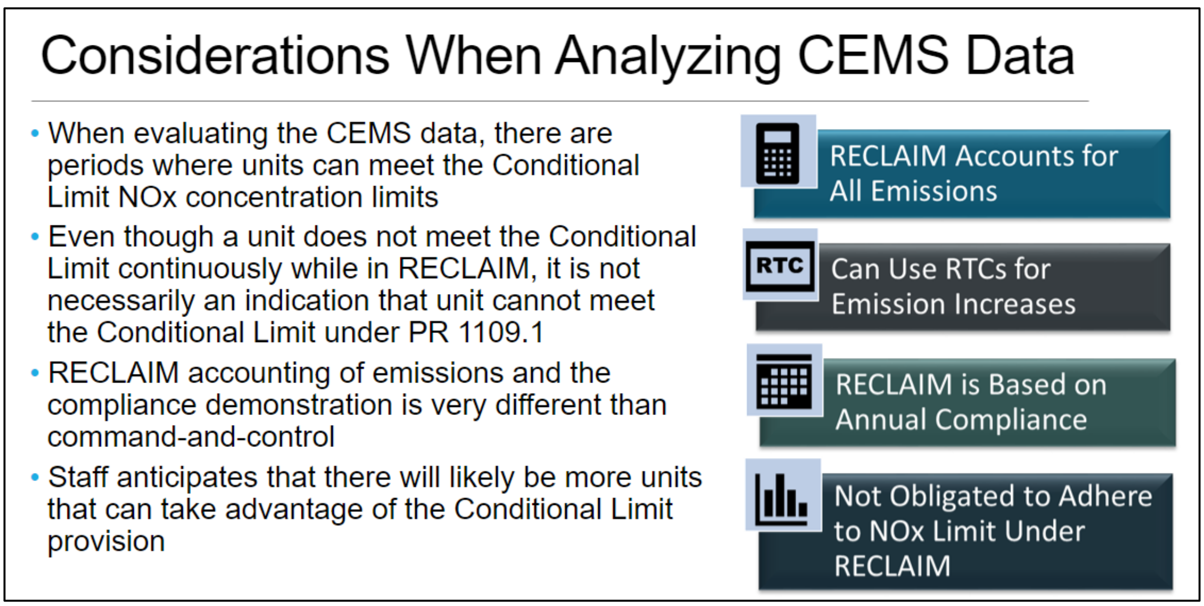
Evaluating Conditional Limits

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.



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:



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.

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.

Heaters 40 – 110 MMBtu/hr			
Potential Near Limit (ppm)*	Cost-Effectiveness of Remaining Units	Number Units Meeting Near Limit*	Potential Emissions (tpd)
No Near Limit	**$53,000**	**0/67 unit**	**Baseline**
10	$53,000	1/67 unit	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.

Heaters ≥40 – 110 MMBtu/hr			
Potential Near Limit (ppm)	Cost-Effectiveness of Remaining Units	Number Units Meeting Near Limit	Potential Emission Reduction if 5 ppm Cost-Effective(tpd)
No Near Limit	**$53,000**	**0/67 unit**	**Baseline**
18	$48,000	12/67 units	0.05
18	$50,000	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 $50,000, 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 had a very high cost-effectiveness of almost $300,000. While there is no established threshold for incremental coast-effectiveness, staff concluded a NOx emission limit of 5 ppmv represented BARCT.

Heaters 40 – 110 MMBtu/hr					
50 ppm		5 ppm*		2 ppm	
Cost Effectiveness	Emission Red (tpd)	Cost Effectiveness	Emission Red (tpd)	Cost Effectiveness	Emission Red (tpd)
$40,000	0.33	$50,500	1.66	$94,000	1.99

* Excludes conditional limit units

	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

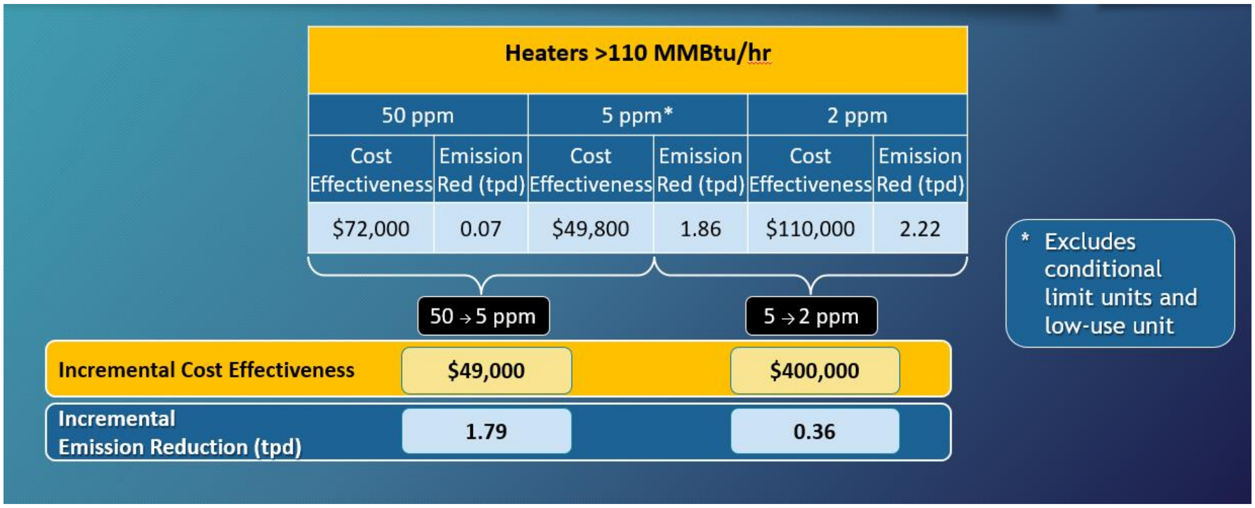
Staff conducted the assessment using the iterative process at different concentration limits but for devices with a potential to achieve greater than 20 tons per year reduction were not excluded from the category as conditional limits – these units will have to retrofit to meet Table 1 limits if they 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.

Heaters >110 MMBtu/hr			
Potential Near Limit (ppm)*	Cost-Effectiveness of Remaining Units	Number Units Meeting Near Limit*+	Potetnial Emissions (tpd)
No Near 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.

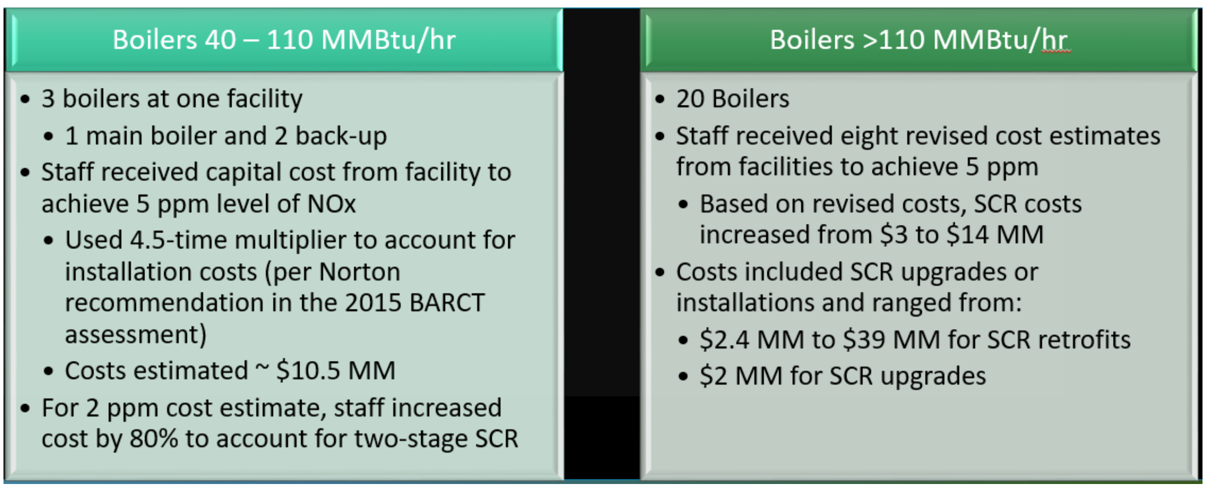
Heaters >110 MMBtu/hr			
Potential Conditional Limit (ppm)*	Cost-Effectiveness of Remaining Units	Number Units Meeting Conditional Limit*+	Potential Emission Reduction if 5 ppm Cost-Effective (tpd)
No Conditional Limit	**$56,000**	**0/51 unit**	**None**
22	$50,000	13/51 units*	0.23
22	$49,800	12/51 units**	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.



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:



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.

Staff Comment:
No near limit provision needed

Boilers 40 – 110 MMBtu/hr					
50 ppm		5 ppm		2 ppm	
Cost Effectiveness	Emission Red (tpd)	Cost Effectiveness	Emission Red (tpd)	Cost Effectiveness	Emission Red (tpd)
$13,000	0.024	$25,000	0.049	$46,000	0.051

	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.

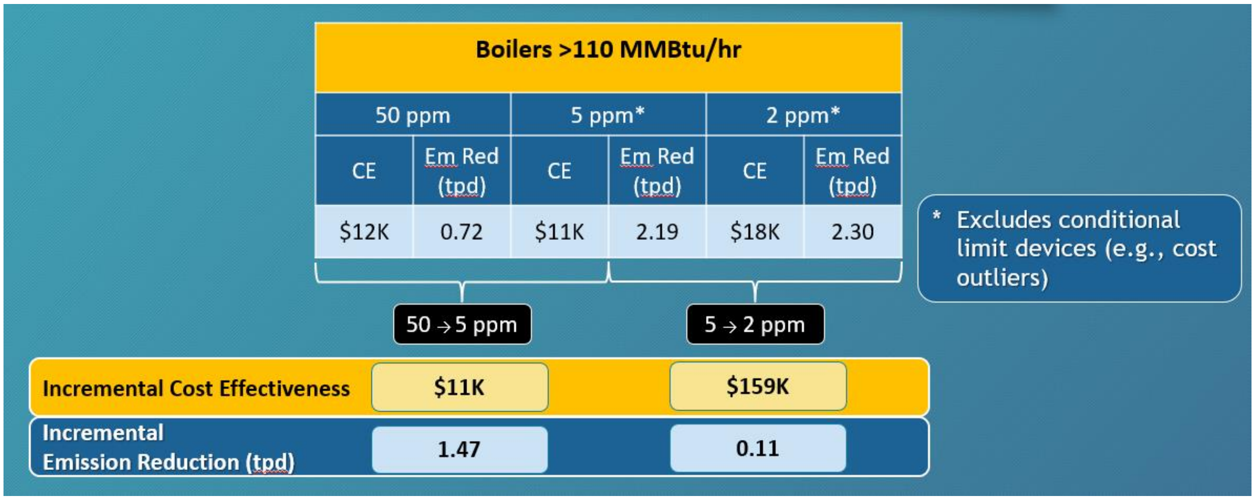
At Working Group Meeting #22, staff initially stated that no cost outliers were identified in greater than 110 MMBtu/hr category. However, upon review of the cost-effectiveness data and CEMS data, staff identified:

- 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.

Boilers >110 MMBtu/hr			
Potential Near Limit (ppm)*	Cost-Effectiveness of Remaining Units	Number Units Meeting Near Limit*+	Forgone Emission Reductions (tpd)
No Near Limit	**$12,000**	**0/17 unit**	**None**
7.5	$11,000	5/17 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.



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.

Cost-Effectiveness		
Heater Category	2 ppm (LNB & SCR)	5 ppm (SCR Upgrade)
SMR Heaters	$138,781	$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.

Heater	Current NOx Control	NOx Control Required to meet 5 ppm	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.

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% O2 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.

Cost-Effectiveness
7.2 ppm→5 ppm NOx Limit
$242,000

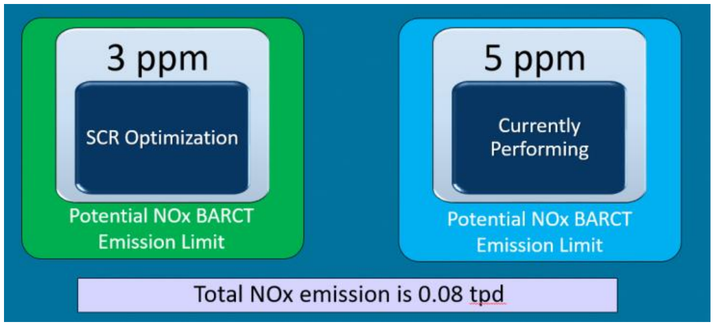
Staff concluded that it was not cost-effective for these outlier units to retrofit to 5 ppmv, so staff proposed a near conditional limit of 7.5 ppmv for the SMR heaters. Staff removed these outliers from the SMR heater category evaluation and re-evaluated the costs for the remaining units.

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 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% O2 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.



It was determined that it was not incrementally cost-effective for the unit to go to 3 ppmv and since the unit is already performing at 5 ppmv, staff proposed a BARCT limit of 5 ppmv at 15% O2.

Cost-Effectiveness		
Heater Category	3 ppm (SCR Upgrade)	5 ppm
SMR and 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 is 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

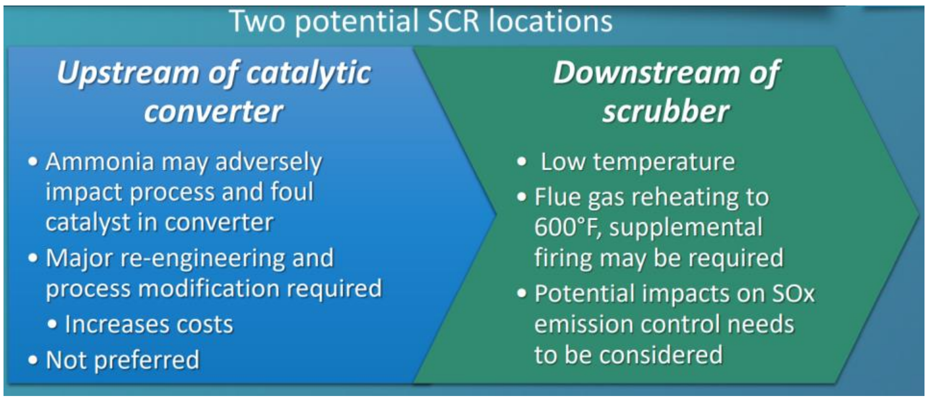
There are two sulfuric acid plant furnaces in this category – one is an operating unit within a refinery and the other is a standalone plant. Both facilities regenerates spent sulfuric acid used in the refinery alkylation process where the main feedstock is spent sulfuric acid. Depending on the ratio 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™.

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.

Selective Catalytic Reduction (SCR)

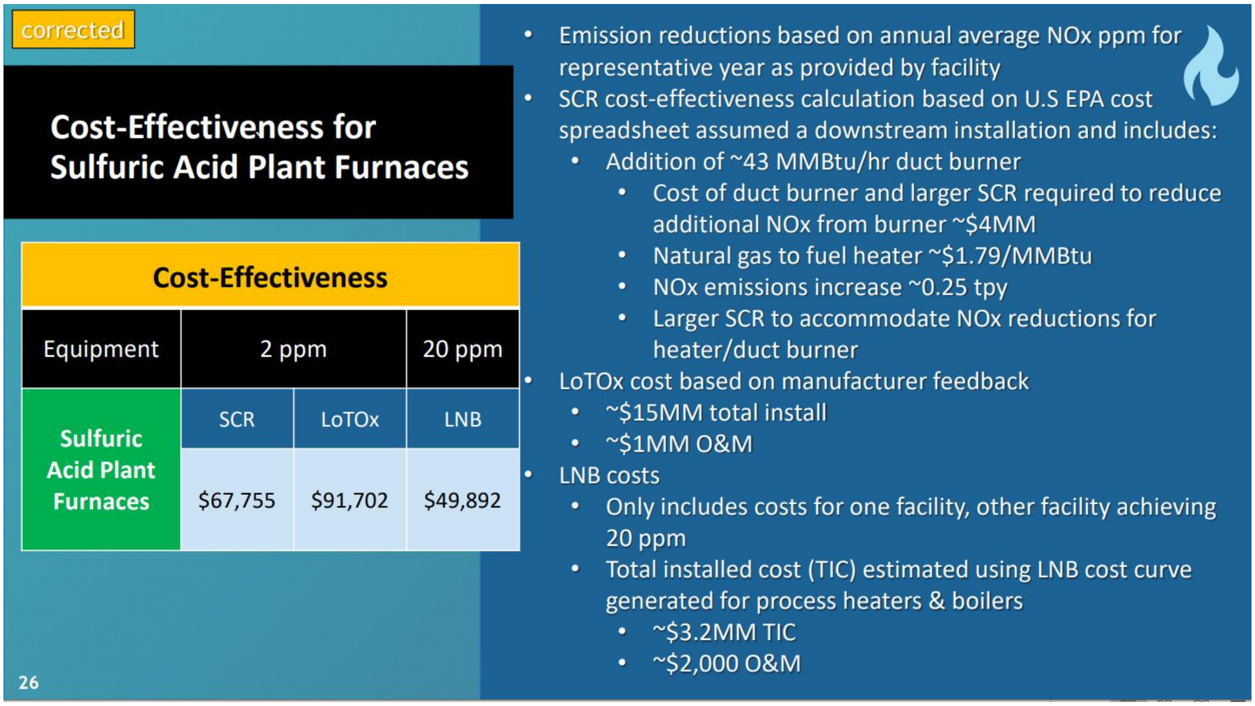
For SCR, staff identified two potential locations in the production process where it can be installed, Upstream of the catalytic converter and downstream of the scrubber. For each location staff also identified several potential issues with SCR that may impact the feasibility and costs.



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).

After meeting with manufacturer sand receiving estimates, staff conducted the cost effectiveness based on a potential BARCT limit of 20 ppmv and 2 ppmv. 20 ppmv is based LNB cost provided by the facilities and 2 ppmv based on SCR and LoTOx™. LoTOx™ based on vendor quote and SCR was estimated using the U.S. EPA cost spreadsheet.



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.

Cost-Effectiveness		
Heater Category	2 ppm (LNB + SCR)	20 ppm (LNB)
Start-Up Heaters	$2.2 MM	$334,630
Start-Up Boiler	$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

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				
Process Heaters (size in MMBtu/hour)							
<20	22	40/9	--	2 hours	0.5	--	$0
≥20 - <40	45	40/9	--	2 hours	0.5	--	$0
≥40 - ≤110	67	5	18	24 hours	1.96	1.63	$50,500
>110	51	5	22	24 hours	2.60	1.79	$49,800

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)							
<20	2	40/5	--	2 hours	0.01	--	$0
≥20 - <40	3	40/5	--	2 hours	0.01	--	$0
≥40 - ≤110	3	5	--	24 hours	0.052	0.05	$25,000
>110	20	5	7.5	24 hours	2.50	2.19	$11,000

Steam Methane Reformer Heaters

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				
SMR Heaters							
All	11	5	7.5	24 hours	1.02	0.62	$17,000

Steam Methane Reformer Heater with Gas Turbine

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				
SMR Heater & Gas Turbine							
All	2	5	--	24 hours	0.082	--	$0

Startup Heaters

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				
Startup Heaters (MMBtu/hour)							
≥40 - ≤110	2	Low-Use	--	--	0.002	--	$0
>110	3	Low-Use	--	--	0.0007	--	$0

Sulfuric Acid Furnace

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				
Sulfuric Acid Furnace							
Furnace	2	30	--	365 day	0.097	--	$0

Start-up Heaters and Boilers located at Sulfuric Acid Plants

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				
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.

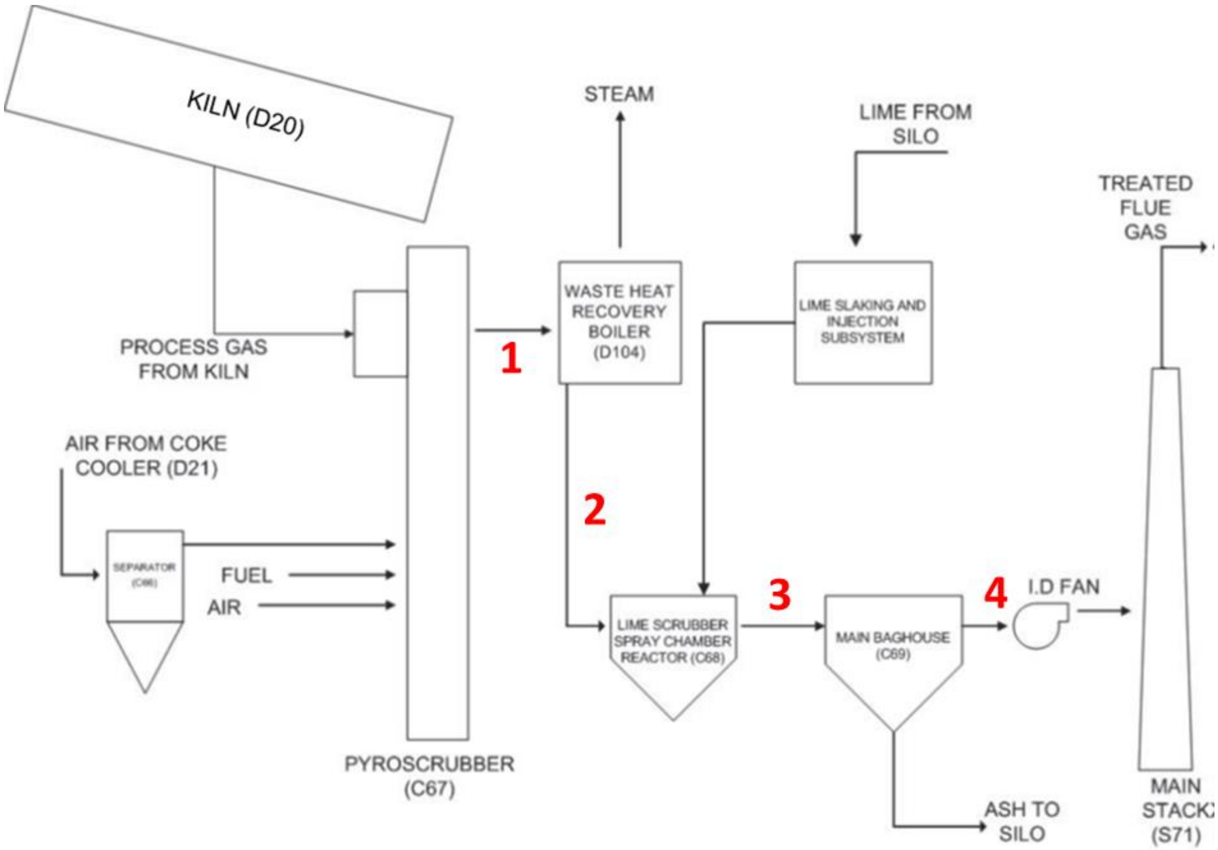


Figure C-1. Coke Calciner Process and Potential Locations for NOx Control (Numbered in Red)

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 identified 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's 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 NEC 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 NEC 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 dayof 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 NEC 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.

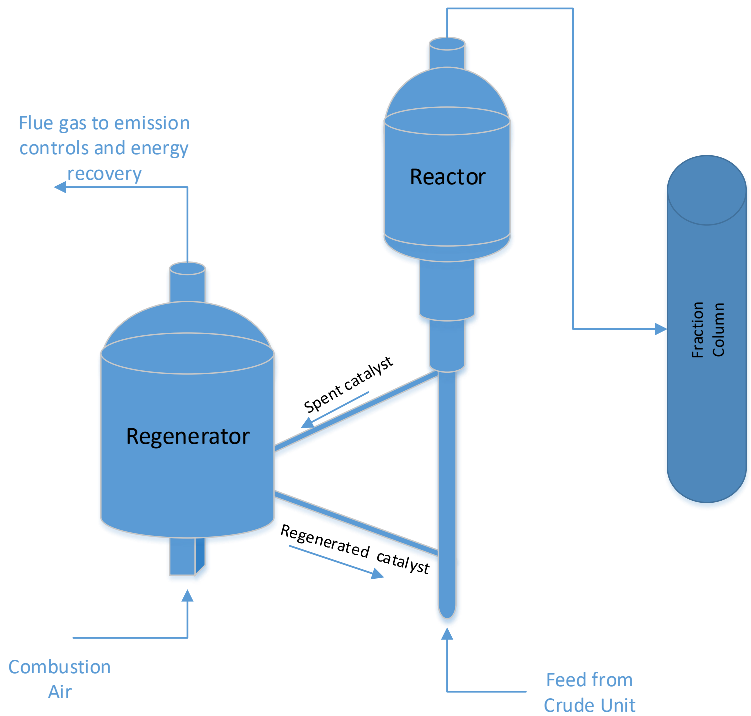


Figure D-1. Simplified Schematic of FCCU Process

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% O2 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 f existing FCCUs, and consulting with the NOx control technology manufacturers, staff concludes that a BARCT NOx limit of 2 ppmv at 3% O2 NOx BARCT is technically feasible.

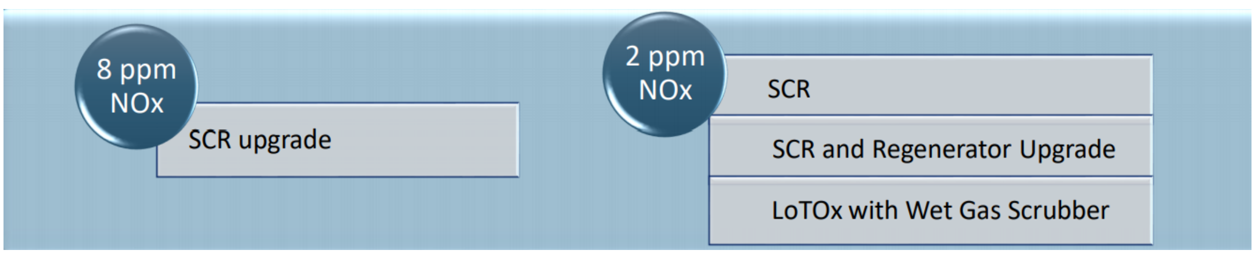
Costs and Cost-Effectiveness Analysis

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 reductions of 0.67 tons per day. In March of 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. 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.

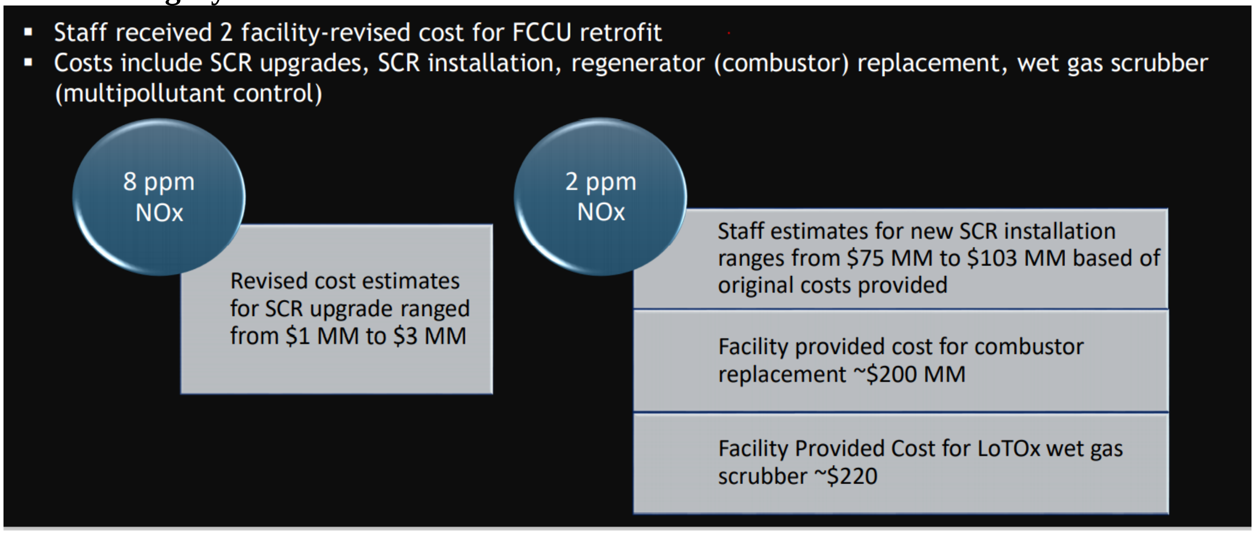


- 2 units without NOx Controls
  - 1 unit is in process of installing a SCR designed for 2 ppm
- 3 units with NOx Controls
  - 1 unit performing well below 2 ppm (annual average)
  - 2 units with SCR that would need:
    - SCR replacement and new regenerator to achieve 2 ppm
    - Upgrades to existing SCR to achieve 8 ppm

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 cost 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.

	Multi-Pollutant Scrubber	SCR
Estimated Present Worth Value	$218 MM	$ 76 MM
Emission Reductions (Lifetime tons)	NOx: 2,071 SOx: 2,027	NOx: 2,071
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-4. 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	$108,000	0.32
	5	7 day	New Regenerator		
Incremental Cost-Effectiveness (8 ppmv to 2 ppmv) Including Outliers					
	2	365 day	New SCR	$127,000	0.25
	5	7 day	New Regenerator		

	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.

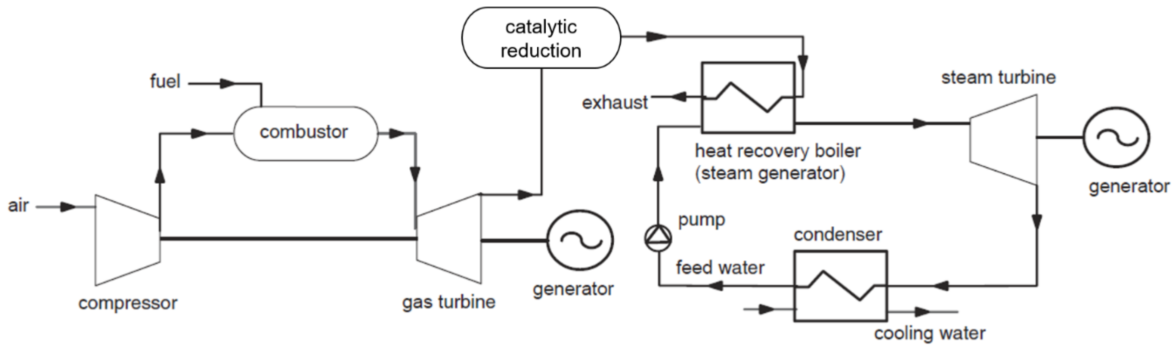


Figure E-1. Combined Cycle Gas Turbine Diagram

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**
Refinery Gas Turbines	–	2 ppmv at 15% O_2, dry

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 NEC 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 the U.S. EPA's SCR cost model in present worth value. As such, the cost effectiveness to go from 2.5 ppmv to 2 ppmv is $570,000 per ton of NOx reductions, and thus not cost effective. 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 are 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.

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. A 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%, O2, 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 are 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 NEC'S 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.

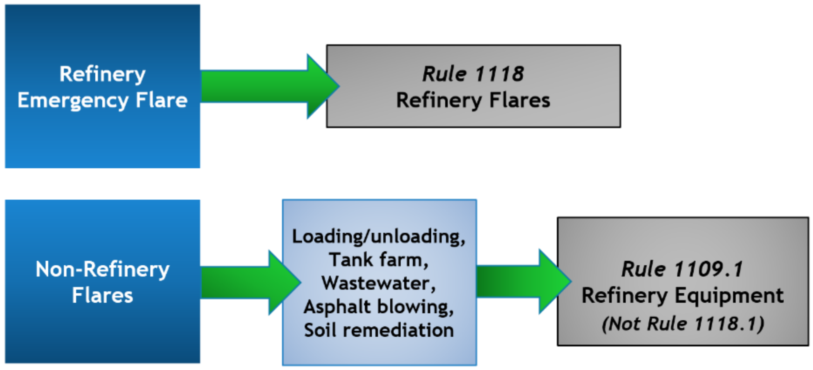


Figure G-1. South Coast AQMD Flare Regulations

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. Staff is proposing to limit the NOx emissions (1.5 lbs/day or 550 lbs/year) not to exceed averaged over every two consecutive years as the best option for the one open flares because of its intermittent and historically low usage, as well as providing flexibility if there is an anomaly year. In addition, when the burners are being replaced, the cleanest technology should be installed.

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 BASELINE 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)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 1 Remaining Emissions (tons)	Table 2 NOx Limit	Table 2 Remaining Emissions (tons)
D641	Heater	365			5		22.0	
D643	Heater	220			5		22.0	
D451	Heater	102			5		18.0	
D3053	Gas Turbine	506			2		2.5	
D203	FCCU				2		8.0	
D2198	Gas Turbine	560			3		N/A	
D20	Heater	217			5		22.0	
D625	Heater	63			5		18.0	
D617	Heater	57			5		18.0	
D623	Heater	63			5		18.0	
D2207	Gas Turbine	560			3		N/A	
D502	Heater	70			5		18.0	
D619	Heater	57			5		18.0	
D504	Heater	77			5		18.0	
D618	Heater	57			5		18.0	
D620	Heater	57			5		18.0	
D2216	Boiler	342			5		7.5	
D82	Heater	315			5		22.0	
D83	Heater	315			5		22.0	
D84	Heater	219			5		22.0	
D159	Heater	176			5		22.0	
D160	Heater	176			5		22.0	
D161	Heater	176			5		22.0	
D955	SRU/TGI	58			30		N/A	
D927	SRU/TGI	30			30		N/A	
D466	Heater	33			40		N/A	
D911	SRU/TGI	30			30		N/A	
D390	Heater	31			40		N/A	
D453	Heater	44			5		18.0	
C3493	Vapor Incinerator	3			30		40.0	
D1910	Heater	37			40		N/A	
D398	Heater	19			40		N/A	
C2158	Vapor Incinerator	3			30		40.0	

CHEVRON								
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Representative NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**
D428	Heater	36			40		N/A	
D364	Heater	26			40		N/A	
C3806	Vapor Incinerator	2			30		40.0	
D3778	Heater	78			5		18.0	
D3695	Heater	83			5		18.0	
D473	Heater	88			5		18.0	
D472	Heater	123			5		22.0	
D471	Heater	177			5		22.0	
D3031	Heater	199			5		22.0	
D3530	SMR Heater	653			5		7.5	
D4354	Gas Turbine	509			2		2.5	
C4344	SRU/TGI	50			30		N/A	
FACILITY TOTAL		**7,063**	**0**			**-**		**-**

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)**
D688	Wilm	Boiler	250			5		7.5	
D154	Wilm	Heater	110			5		18.0	
D155	Wilm	Heater	100			5		18.0	
D156	Wilm	Heater	70			5		18.0	
D157	Wilm	Heater	42			5		18.0	
D158	Wilm	Heater	24			5		18.0	
D1	Wilm	FCCU	-			2		8.0	
D687	Wilm	Boiler	179			5		7.5	
D135	Wilm	Heater	116			5		22.0	
D136	Wilm	Heater	68			5		22.0	
D137	Wilm	Heater	71			5		22.0	
D138	Wilm	Heater	56			5		22.0	
D139	Wilm	Heater	19			5		22.0	
D684	Wilm	Boiler	304			5		7.5	
D828	Wilm	Gas Turbine	646			3		N/A	
D264	Wilm	Heater	135			5		22.0	
D194	Wilm	Heater	60			5		18.0	
D146	Wilm	Heater	76			5		18.0	
D686	Wilm	Boiler	304			5		7.5	
D220	Wilm	SMR Heater	350			5		7.5	
D333	Wilm	Sulfuric Acid Furnace	74			30		N/A	
D262	Wilm	Heater	37			40		N/A	
D148	Wilm	Heater	27			40		N/A	
D259	Wilm	Heater	39			40		N/A	
D152	Wilm	Heater	30			40		N/A	
D150	Wilm	Heater	38			40		N/A	
D133	Wilm	Heater	35			40		N/A	
D161	Wilm	Heater	31			40		N/A	
D39	Wilm	Heater	29			40		N/A	
D329	Wilm	Heater	29			40		N/A	
D142	Wilm	Heater	17			40		N/A	
D129	Wilm	Heater	27			40		N/A	
D163	Wilm	Heater	14			40		N/A	
D260	Wilm	Heater	17			40		N/A	

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)**
D40	Wilm	Heater	10			40		N/A	
D1720	Wilm	Heater	41			5		18.0	
D332	Wilm	Sulfuric Acid Furnace	15			30		N/A	
D1349	Wilm	SMR Heater	460			5		7.5	
C436	Wilm	SRU/TGI	20			30		N/A	
C456	Wilm	SRU/TGI	20			30		N/A	
D430	Carson	Boiler	352			5		7.5	
D210	Carson	SMR Heater	340			5		7.5	
D59	Carson	Heater	350			5		22.0	
D174	Carson	Heater	70			5		18.0	
D105	Carson	Heater	175			5		22.0	
D104	Carson	Heater	175			5		22.0	
D79	Carson	Heater	154			5		22.0	
D78	Carson	Heater	154			5		22.0	
D429	Carson	Boiler	352			5		7.5	
D713	Carson	Heater	22			40		N/A	
C292	Carson	SRU/TGI	15			30		N/A	
C294	Carson	SRU/TGI	28			30		N/A	
FACILITY TOTAL			**3,989**				**-**		**-**

Table H-3. Tesoro Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

TESORO									
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)**
D27	Carson	Heater	550			5		22	
D20	Carson	Coke Calciner	120			5		N/A	
D570	Carson	SMR Heater	650			5		7.5	
D629	Carson	Heater	173			5		22	
D535	Carson	Heater	310			5		22	
D532	Carson	Heater	255			5		22	
D31	Carson	Heater	130			5		22	
D151	Carson	Heater	130			5		22	
D155	Carson	Heater	130			5		22	
D423	Carson	Heater	80			5		18	
D153	Carson	Heater	130			5		22	
D67	Carson	Heater	120			5		22	
D29	Carson	Heater	150			5		22	
D33	Carson	Heater	100			5		18	
D539	Carson	Heater	52			5		18	
D421	Carson	Heater	82			5		18	
D625	Carson	Heater	39			40		N/A	
C54	Carson	SRU/TGI	52			30		N/A	
D250	Carson	Heater	89			5		18	
C910	Carson	SRU/TGI	45			30		N/A	
C2413	Carson	SRU/TGI	40			30		N/A	
D538	Carson	Heater	39			40		N/A	
D416	Carson	Heater	24			40		N/A	
D626	Carson	Heater	39			40		N/A	
D628	Carson	Heater	39			40		N/A	
D63	Carson	Heater	300			5		22	
D541	Carson	Heater	39			40		N/A	
D1465	Carson	SMR Heater	427			5		7.5	
D627	Carson	Heater	39			40		N/A	
C56	Carson	SRU/TGI	45			30		N/A	
D419	Carson	Heater	52			5		18	
D425	Carson	Heater	22			40		N/A	
D1433	Carson	Heater	13			40		N/A	
D418	Carson	Heater	11			40		N/A	
D417	Carson	Heater	10			40		N/A	
D1233	Carson	Gas Turbine	1,326			3		N/A	
D1239	Carson	Gas Turbine	1,326			3		N/A	
D1226	Carson	Gas Turbine	1,326			3		N/A	
D1236	Carson	Gas Turbine	1,326			3		N/A	
D164	Carson	FCCU				2		8.0	

TESORO									
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)**
D724	Wilm	Boiler	184			5		7.5	
D722	Wilm	Boiler	184			5		7.5	
D76/D77	SRP	Boiler	224			5		7.5	
D812	Wilm	Gas Turbine	392			3		N/A	
D810	Wilm	Gas Turbine	392			3		N/A	
D32	Wilm	Heater	218			5		22	
D89	Wilm	Heater	95			5		18	
D9	Wilm	Heater	200			5		22	
D247	Wilm	Heater	82			5		18	
D248	Wilm	Heater	50			5		18	
D249	Wilm	Heater	29			5		18	
D90	Wilm	Heater	127			5		22	
D146	Wilm	Heater	69			5		18	
D33	Wilm	Heater	252			5		22	
D388	Wilm	Heater	147			5		22	
D214	Wilm	Heater	56			5		18	
D215	Wilm	Heater	36			5		18	
D216	Wilm	Heater	31			5		18	
D217	Wilm	Heater	31			5		18	
D158	Wilm	Heater	204			5		22	
D386	Wilm	Heater	48			5		18	
D387	Wilm	Heater	71			5		18	
D120	Wilm	Heater	45			5		18	
D157	Wilm	Heater	49			5		18	
D218	Wilm	Heater	60			5		18	
D92	Wilm	Heater	37			40		18	
D384	Wilm	Heater	48			5		18	
D385	Wilm	Heater	24			5		18	
D1122	Wilm	Boiler	140			5.0		7.5	
D777	Wilm	SMR Heater	146			5.0		7.5	
D250	Wilm	Heater	35			40		N/A	
D770	Wilm	Heater	63			5		18	
D723	Wilm	Boiler	184			5		7.5	
D725	Wilm	Boiler	184			5		7.5	
FACILITY TOTAL			**13,855**						

Table H-1. Torrance Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

TORRANCE								
Device ID	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 1 Remaining Emissions (tons)	Table 2 NOx Limit	Table 2 Remaining Emissions (tons)
D803	Boiler	309			5		7.5	
D805	Boiler	291			5		7.5	
D367	SMR Heater	527			5		7.5	
D151	FCCU				2		8.0	
D913	Heater	457			5		22.0	
D914	Heater	161			5		22.0	
D917	Heater	91			5		18.0	
D918	Heater	91			5		18.0	
D120	Heater	126			5		22.0	
D930	Heater	129			5		22.0	
D83	Heater	67			5		18.0	
D84	Heater	67			5		18.0	
D85	Heater	74			5		18.0	
D931	Heater	73			5		18.0	
D269	Heater	107			5		18.0	
D920	Heater	108			5		18.0	
D1239	Boiler	340			5		7.5	
D1236	Boiler	340			5		7.5	
C626	Vapor Incinerator	60			30		40.0	
D949	Heater	40			40		N/A	
D234	Heater	60			5		18.0	
D235	Heater	60			5		18.0	
D950	Heater	64			5		18.0	
C686	Vapor Incinerator	4			30		40.0	
D927	Heater	17			40		N/A	
D231	Heater	60			5		18.0	
D232	Heater	60			5		18.0	
D928	Heater	17			40		N/A	
D929	Heater	21			40		N/A	
D1403	Heater	21			40		N/A	
C687	Vapor Incinerator	4			30		40.0	
D925/D926	SMR Heater/GTG	1247			5		7.5	
C952	SRU/TGI	100			30		40.0	
FACILITY TOTAL		**5,193**	-			-		-

Table H-2. Ultramar Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

ULTRAMAR								
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)**
D36	FCCU				2		8.0	
D74	Heater	258			5		22.0	
D3	Heater	159			5		22.0	
D6	Heater	136			5		22.0	
D52	Heater	36			40		N/A	
D22	Heater	95			5		18.0	
D12	Heater	144			5		22.0	
D53	Heater	68			5		18.0	
D8	Heater	49			5		18.0	
D98	Heater	57			5		18.0	
D768	Heater	110			5		18.0	
D1550	Boiler	245			5		7.5	
D73	Heater	30			40		N/A	
D59	Heater	26			40		N/A	
D60	Heater	30			40		N/A	
D429	Heater	30			5		22.0	
D430	Heater	200			5		22.0	
D9	Heater	20			40		N/A	
D378	Boiler	128			5		7.5	
C1260	SRU/TGI	36			30		40.0	
D377	Boiler	39			5		7.5	
D1669	Gas Turbine	342			2		2.5	
FACILITY TOTAL		**2,238**	**-**			**-**		**-**