SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Preliminary Draft Staff Report

Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM

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List of Acronyms

AC	Annual Operating Cost
AER	Annual Emissions Report
AQMP	Air Quality Management Plan
ASC	Ammonia Slip Catalyst
Basin	South Coast Air Basin
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
CARB	California Air Resources Board
CE	Cost Effectiveness
CEMS	Continuous Emissions Monitoring System
CLN™	Cheng Low NOx Control Technology
CM	Control Measure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CR	Catalyst Replacement
CY	Compliance Year
DCF	Discounted Cash Flow Method
DLN/DLE	Dry Low NOx/Dry Low Emissions
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
ER	Emission Reductions
ESP	Electrostatic Precipitator
ETS	Environmental Technology Services
^{o} F	Degree Fahrenheit
FCCU	Fluid Catalytic Cracking Unit
HHV	High Heating Value of Fuel
HRSG	Heat Recovery Steam Generator
H&SC	Health & Safety Codes
GF	Growth Factor
LCF	Levelized Cash Flow Method
LoTOx™	Low Temperature Oxidation Process for NOx Control
NAAQS	National Ambient Air Quality Standards
NEC	Norton Engineering Consultants
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
N_2O	Nitrous Oxide
NOx	Nitrogen Oxides
OCS	Outer Continental Shelf
OAQPS	Office of Air Quality Planning and Standards
PAR	Proposed Amended Rule or Proposed Amended Regulation
ppm	Parts Per Million
PWV	Present Worth Values
RACM	Reasonably Achievable Control Measure
RACT	Reasonably Achievable Control Technology
RECLAIM	Regional Clean Air Incentive Market Program
RTC	RECLAIM Trading Credit

SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOx	Sulfur Oxides
SRU/TG	Refinery's Sulfur Recovery Unit /Tail Gas Treating Unit
TIC	Total Installed Costs
tpd or TPD	Tons Per Day
Ultra-Cat™	Ultra-Cat Catalyst Filter Manufactured by Tri-Mer Corporation
WHB	Waste Heat Boiler
WGM	Working Group Meeting
WSPA	Western States Petroleum Association

Executive Summary

Background

On October 15, 1993, the South Coast Air Quality Management District (SCAQMD)'s Governing Board adopted Regulation XX - Regional Clean Air Incentives Market (RECLAIM). Regulation XX includes 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 sources located at RECLAIM facilities. RECLAIM was designed to provide equivalent emission reduction in the aggregate for the facilities in the program, with flexibility for each facility to find the most cost-effective approach. The program requires robust monitoring to ensure compliance. Over the past more than 20 years, the program has resulted in significant emission reductions. The RECLAIM program started with 392 NOx facilities in 1993. By the end of compliance year 2013, there were 275 facilities in the NOx RECLAIM universe.

Best Available Retrofit Control Technology for RECLAIM

When the NOx RECLAIM program was first adopted, the NOx RECLAIM facilities were issued NOx annual allocations (also known as facility caps), which declined annually from 1993 until 2003 and remained constant after 2003. The annual allocations issued to the NOx RECLAIM facilities reflected the levels of Best Available Retrofit Control Technology (BARCT) envisioned to be in place at the RECLAIM facilities, and were the result of a BARCT analysis conducted in 1993. The NOx RECLAIM facilities are required to reconcile the actual facility emissions with the annual allocations. A BARCT reassessment is required by the California Health & Safety Codes (H&SC) §40440 and §39616 to assess the advancement in control technology and to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach and that emission reductions from the program contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). The SCAQMD conducted a BARCT reassessment for NOx in 2005 and another for SOx in 2010, and subsequently reduced the facility annual allocations. RECLAIM facilities have the flexibility to install air pollution control equipment, change their operations, or purchase RECLAIM Trading Credits (RTCs).

Ozone Non-Attainment Status

With regards to the ozone standards, on March 12, 2008, the EPA strengthened its ground-level 8-hour ozone standard from 0.08 parts per million (ppm) to 0.075 ppm. On May 21, 2012, the EPA classified two areas in the country, the South Coast and the San Joaquin Valley, as "Extreme" non-attainment areas with respect to the 2008 8-hour ozone standard. The attainment dates for the 1997 and 2008 ozone standards are June 15, 2024 and July 20, 2032, respectively. NOx is a precursor for ozone. Reduction of NOx emissions is necessary for the Basin to attain the ozone ambient air quality standards in 2024 and 2032.

2012 Air Quality Management Plan and Control Measure CMB-01

The SCAQMD developed and adopted the 2012 Air Quality Management Plan (AQMP) in partnership with CARB, U.S. EPA, SCAG and stakeholders throughout the region to outline the strategy to meet and maintain the state and federal air quality standards. The 2012 AQMP identified control measures needed to attain the federal 24-hour standard for PM2.5 by 2014 and provided updates on progress towards meeting the 8-hour ozone standard in 2024. Control Measure CMB-01 – Further NOx Reduction for RECLAIM is one of the control measures included in the 2012 AQMP. Control Measure CMB-01 called for a reassessment of BARCT for NOx RECLAIM facilities and envisioned that a total of 2-3 tons per day (tpd) of NOx emission reductions could be achieved in Phase I with an additional of 1-2 tpd NOx in Phase II. CMB-01 Phase I served as a PM2.5 SIP contingency measure for the 2012 AQMP, and if emission reductions were not needed in Phase I, the RTC reductions estimated for Phase I would be combined with the total reductions that could be achieved in Phase II. It was anticipated that NOx emissions reductions from both phases would also contribute to meeting the ozone standards in 2024 and 2032.

Current Emissions and RTC Holdings

The 2011 audited actual emissions were 20 tons per day (tpd) for the RECLAIM universe (59% from the refineries and 41% from the non-refinery sector). For power plants, staff used 2012 emissions instead of 2011 due to several reasons: 1) local power plants in the region operated more in 2012 to make up for the ceasing operations of the San Onofre Nuclear Generation Station (SONGS), 2) the commissioning of new power plants in the region was reflected more accurately in 2012, and 3) a recent shift in the use of renewable energy sources, such as wind, solar, and water, and their inherent intermittency resulted in the use of peaking units with increased numbers of startups and thus emissions. The 2011/2012 baseline emissions for the NOx RECLAIM universe in this analysis were about 20.7 tpd.

The RECLAIM Trading Credit (RTC) holdings for the RECLAIM universe were 26.5 tpd, in which the refinery sector held 51% of the RTCs, power plants 21%, investors 4% and other RECLAIM facilities 24%.

Proposed BARCT, Emission Reductions, and RTC Reductions

The BARCT analysis resulted in the BARCT levels shown in Table EX.1. For the refinery sector, a new level of BARCT is proposed for fluid catalytic cracking units, boilers/heaters >40 mmbtu/hr, gas turbines, coke calciners, and sulfur recovery and tail gas incinerators. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal melting furnaces >150 mmbtu/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for power plants.[1]

Table EX.1 - Summary of Proposed BARCT (May 2015)

Refinery Sector	2015 BARCT Level	Emission Reductions (tpd)
Fluid Catalytic Cracking Units	2 ppmv at 3% O2	0.43
Refinery Boilers and Heaters >40 mmbtu/hr	2 ppmv or 0.002 lb/mmbtu	0.96
Refinery Gas Turbines	2 ppm at 15% O2	4.14
Coke Calciner	10 ppmv at 3% O2	0.17
Sulfur Recovery Units Tail Gas Incinerators	2 ppmv at 3% O2 or 95% reduction	0.32
	Total	**6.02**
Non-refinery Sector	**2015 BARCT Level**	**Emission Reductions (tpd)**
Container Glass Melting Furnaces	80% reduction	0.24
Sodium Silicate Furnace	80% reduction	0.09
Metal Heat Treating Furnaces >150 mmbtu/hr	9 ppmv at 3% O2	0.56
Gas Turbines (non-OCS)	2 ppmv at 15% O2	1.04
Internal Combustion Engines (non-OCS)	11 ppmv at 15% O2	0.84
Cement Kilns	0.5 lbs/ton	1.29 (note)
	Total	**2.77**

Note: The 1.29 tpd emission reductions from cement kilns were not included in the 2.77 tpd emission reductions because cement facility was not in operation in 2011. Cement kilns are the #1 source of NOx emissions in 2008, thus staff conducted a BARCT analysis for cement kilns and reduced the remaining emissions projected to the 2023 level for the cement facility to the BARCT level.

As shown in Table EX.1, the total BARCT-equivalent emission reductions are 8.79 tpd (6.02 tpd for the refinery sector and 2.77 tpd for the non-refinery sector.) Due to projected growth,[2] the remaining emissions in 2023 at these proposed 2015 BARCT levels would be 10.18 tpd (2.71 tpd for the refinery sector and 7.47 tpd for the non-refinery sector.) Staff has added a 10% compliance margin to the remaining emissions, has accounted for uncertainties that arose in the BARCT analysis and shut down facilities, and has also proposed an adjustment account to hold RTCs for power plants to meet their NSR holding obligations. This results in total proposed NOx RTC

[1] Staff conducted a BARCT analysis focusing on the top 37 NOx emitting facilities in 2011, and a cement plant which was the #1 top NOx emitting source in 2008. The BARCT analyses with detailed information are in the appendices (Appendices A-J of Part I for the refinery sector, and Appendices M-S of Part II for the non-refinery sector.)

[2] The growth factor for the refineries is 1. Power plants are expected to be more efficient with growth factor of 0.89. The average growth factor for other non-refinery facilities is 1.1.

reductions of 14 tpd from the current RTC holdings of 26.5 tpd.[3] The remaining RTCs for the NOx RECLAIM universe would be 12.5 tpd (26.5 tpd – 14 tpd = 12.5 tpd), which is about 2.3 tpd or almost 23% above the projected remaining emissions from RECLAIM NOx sources in 2023. Staff is proposing to implement the 14 tpd RTC reductions over a 7-year period from 2016 to 2022 but as expeditiously as possible to help the Basin meet the PM2.5 standard deadlines as well as the ozone standard by 2024 and 2032.

Staff is proposing to distribute the 14 tpd NOx RTC reductions to 65 facilities and investors that hold 90% of the 26.5 tpd RTCs. Investors are grouped with the refineries and treated as a facility. The remaining 210 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there was no new BARCT for the types of equipment and operation at these facilities. Staff's current proposal is to weight the amount of shave considering the technology available to different facility types and is summarized below:

67% shave for 9 refineries and investors
47% shave for 30 power plants
47% shave for 26 non-major facilities
0% shave for 210 remaining facilities

Staff is proposing the following implementation schedule for NOx RTC reductions:

2016 – 4 tons per day
2018 – 2 tons per day
2019 – 2 tons per day
2020 – 2 tons per day
2021 – 2 tons per day
2022 – 2 tons per day

Over the past five years from 2009-2013, the unused RTCs in the NOX RECLAIM program ranged from 5 tpd to 8 tpd, and thus staff is proposing a reasonable 4 tpd RTC reduction in 2016. Additional BARCT implementation will take about 2 – 4 years for planning, permitting, and construction, and thus staff is proposing the remaining shave of 10 tpd to take place over five years from 2018 to 2022. Staff continues to seek input from stakeholders on the proposal, including the schedule for the RTC reductions.

The BARCT analyses are described in Chapter 3, the costs and cost effectiveness of the proposal are described in Chapter 4, the RTC reductions are estimated in Chapter 5, and the proposed changes in rule language are described in Chapter 6.

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[3] RTC Reductions = RTC Holdings – Remaining Emissions in 2023 - Adjustments = 14 tpd. Refer to Chapter 5 and Appendix U of Part III for detailed information.

Public Process

The public process for PAR XX – NOx RECLAIM is summarized in Table EX.2. Staff began this rulemaking process in the 4th quarter 2012. In 2013, staff formed a RECLAIM Working Group that included members representing NOx RECLAIM facilities, the Western States Petroleum Association (WSPA), the environmental community, as well as CARB and U.S. EPA to discuss potential amendments to the NOx RECLAIM program. The first meeting was conducted on January 31, 2013. A list of participants is shown in Table EX.3.

To gather pertinent information for rule development, staff sent out Survey Questionnaires to 38 facilities, including the top 37 emitting facilities in 2011 and a cement facility which was the #1 NOx emission sources in 2008. Since January 2013, eleven Working Group Meetings were held to discuss potential BARCT levels for major NOx sources at the top 38 facilities, the emissions inventory, potential for emission reductions, and proposals for RTC reductions.[4] In addition, in September 2014, staff contracted two consultants (Environmental Technology Services, Inc. (ETS) and Norton Engineering Consultants Inc. (NEC)) to conduct independent BARCT analyses. The consultants and staff visited a glass manufacturing facility, a cement manufacturing facility, and six refineries to assess the availability of space for the installation of additional controls and to discuss BARCT issues and concerns with the stakeholders. The consultants completed their analyses in December 2014, and staff held the 8th Working Group Meeting in January 7, 2015 to report on the consultants' findings to the stakeholders. A CEQA and Socioeconomic scoping session was held in January 8, 2015 and staff received ten comment letters. From January to March 2015, staff reviewed the consultants' analyses and addressed comments received in response to the CEQA and Socioeconomic scoping session. Staff also extended the contract for NEC to allow time to produce the confidential proprietary information reports for each refinery, and this task was completed on April 10, 2015.

In addition to the eleven Working Group Meetings, staff met more than a dozen times with various stakeholders to discuss BARCT and the allocation reduction distribution (shave) methodology. Staff also met with a number of air pollution control manufacturers to discuss control technologies, and invited the manufacturers to write manuscripts and give presentations at the 2014 Air & Waste Management Association annual conference in Long Beach. Several refinery representatives participated in the discussions at the conference.

A Public Workshop is scheduled for July 22, 2015 and the Public Hearing is currently scheduled for October 2, 2015.

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[4] The Survey Questionnaires for the refineries and non-refineries are in Appendix L and Appendix T, respectively. The detailed BARCT analyses are in the relevant appendices (Appendices A-J for refinery sector and Appendices M-S for non-refinery sector.) Staff focused on the top 37 emitting facilities contributing more than 85% of the 2011 emissions and the cement plant which was #1 NOx emission sources in 2008. Staff looked at other sources in the remaining 237 facilities and did not identify any more stringent BARCT for these facilities.

Table EX.2 - Summary of Public Process

Calendar Year 2013	
January 31, 2013	RECLAIM Working Group was formed. The 1st RECLAIM Working Group Meeting was conducted
March 20, 2013	2nd RECLAIM Working Group Meeting
June 13, 2013	3rd RECLAIM Working Group Meeting. Staff conducted a Survey to gather information for rule development.
September 19, 2013	4th RECLAIM Working Group Meeting
Calendar Year 2014	
January 22, 2014	5th RECLAIM Working Group Meeting
March 18, 2014	6th RECLAIM Working Group Meeting
March 21, 2014	1st Stationary Source Committee Meeting
July 31, 2014	7th RECLAIM Working Group Meeting
September 2014 – December 2014	Staff contracted ETS and NEC to conduct independent BARCT analyses for the non-refinery and refinery sectors. The consultants and staff visited the facilities to discuss BARCT issues with the stakeholders and assess space availability. The consultants finalized their analyses and reports in December 2014.
Calendar Year 2015	
January 7, 2015	8th RECLAIM Working Group Meeting. Staff presented the results of the consultants' analyses to the Working Group Meeting.
January 8, 2015	A CEQA and Socioeconomic Scoping session was held. About 10 comment letters were received.
January – March	Staff conducted a review of the consultants' analyses and addressed the comments received in the CEQA and Socioeconomic Scoping sessions.
April 10, 2015	The contract for NEC was extended to separate confidential reports for the refineries. This task was completed April 10, 2015
April 29, 2015	9th RECLAIM Working Group Meeting.
June 4, 2015	10th RECLAIM Working Group Meeting.
July 9, 2015	11th RECLAIM Working Group Meeting.
July 22, 2015	Public Workshop. Release Preliminary Draft Staff Report and Rule Language.
October 2, 2015	Public Hearing

Table EX.3 - List of Participants

Organizations in RECLAIM Task Force
California Council for Environmental Balance (CCEEB)
Regulatory Flexibility (RegFlex)
South Coast Air Quality Alliance (SCAQA)
Western States Petroleum Association

Facilities
Air Products
California Portland Cement Company
Chevron
ExxonMobil
Owen Brockway
Paramount
Phillips66
Tesoro
Ultramar and other facilities in the top 37 emitting facilities

Manufacturers of Control Devices & Consultants
BASF
BELCO
Cheng Low NOx
ClearSign
Cormetech
ETS
Elex CEMCAT
Grace Davidson
Great Southern Flameless
Haldor Topsoe
INTERCAT
MECS
Mitsubishi
NEC
Tri-Mer

Others
California Air Resources Board
Bay Area Air Pollution Control District
Santa Barbara Air Pollution Control District
San Joaquin Valley Air pollution Control District
U.S. Environmental Protection Agency

Chapter 1 – Background

Legislative Authority

The California Legislature created the SCAQMD in 1977 as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin). The H&SC requires the SCAQMD to adopt an AQMP outlining how the Basin will achieve and maintain state and federal ambient air quality standards by the earliest practicable date. In addition, the SCAQMD is required to adopt rules and regulations to implement the AQMP. The SCAQMD's rules and regulations must contain BARCT for existing sources. The SCAQMD is required to conduct a BARCT reassessment on a regular basis to capture the advancement in control technology and to ensure that RECLAIM facilities achieve the emission reductions that would have occurred under a command-and-control approach and that emission reductions from the program contribute to the Basin achieving the federal and state ambient air quality standards. The relevant H&S provisions, including a definition of BARCT, are cited below:

H&SC §40460(a): "*... the south coast district board shall adopt a plan to achieve and maintain the state and federal ambient air quality standard.*"

H&SC §40440(a): *"The south coast district board shall adopt rules and regulations that carry out the plan and are not in conflict with state law and federal laws and rules and regulations*."

H&SC §40440(b)(1): " *The rules and regulations adopted ... shall ... require the use of best available control technology for new and modified sources and the use of best available retrofit control technology for existing sources*."

H&SC §39616: *"(RECLAIM must) ... result in an equivalent or greater reduction in emissions at equivalent or less costs compared with current command and control regulations*."

H&SC §40406: "*…best available retrofit technology means an emission limitation that is based on the maximum degree of reduction achievable taking into account environmental, energy, and economic impacts by each class or category of source.*"

Ozone Non-Attainment Status

Relative to the ozone and PM2.5 NAAQS promulgated by the U.S. EPA to protect public health and the environment, the Basin is currently classified as an "extreme" non-attainment area for ozone and is a non-attainment area for annual and 24-hour PM2.5. Scientific studies have found an associations between exposure to particulate matter and ozone and significant health problems, including asthma, chronic bronchitis, reduced lung function, irregular heartbeat, heart attack, and premature death in people with heart or lung disease. Individuals particularly sensitive to air pollution exposure include older adults, people with heart and lung disease, and children.

There are six criteria pollutants that contribute to ambient air pollution for which there are federal NAAQS: ozone, carbon monoxide, lead, particulate matter, sulfur dioxide, and nitrogen dioxide. The effect of reducing emissions of each of these pollutants varies by area depending on the composition, concentrations of these pollutants and other area-specific factors. The federal EPA requires the SCAQMD to implement all reasonably available control measures (RACM) and reasonably available control technology (RACT) considering economic and technical feasibility and other factors to reduce criteria air pollutants.

On March 12, 2008, the EPA strengthened its ground-level 8-hour ozone standard from 0.08 ppm to a level of 0.075 ppm. On May 21, 2012, the EPA classified two areas in the country, the South Coast and the San Joaquin Valley, as "Extreme" non-attainment areas with respect to the 2008 8-hour ozone standard. The attainment dates for the 1997 and 2008 ozone standards are June 15, 2024 and July 20, 2032, respectively. NOx is a major precursor of ozone and PM2.5, and reducing NOx is essential for the Basin to attain the ozone ambient air quality standards while also helping to meet PM2.5 standards. The SCAQMD is working on the 2016 AQMP to address ozone and PM2.5 attainment strategies.

Control Measure CMB-01 of the 2012 AQMP

Control Measure CMB-01 – *Further NOx Reductions from RECLAIM* is one of the control measures specified in the 2012 AQMP. The control measure CMB-01 has 2 phases: Phase I has an estimated reduction of 2–3 tpd NOx and serves as a contingency measure for PM2.5 attainment. A contingency measure is a measure that will be automatically implemented if the basin fails to meet the PM2.5 standards by the attainment date. Based on recent data, the Basin will fail to meet the PM2.5 ambient air quality standards by the original attainment date of 2014 as well as the revised attainment date of 2015. If Phase I was not triggered, CMB-01 anticipated that Phase I reductions would be rolled into Phase II to help attain the ozone standards. In combination, Phase I and Phase II together had estimated reductions of 3-5 tpd with the lower end of emission reduction range committed to in the State Implementation Plan (SIP) yet to be acted on by U.S. EPA. The adoption date and implementation date for Control Measure CMB-01 were estimated to be 2015 and 2020, respectively.

Current NOx RECLAIM Program

On October 15, 1993, the SCAQMD's Governing Board adopted the RECLAIM program and Regulation XX. Regulation XX includes 11 rules that specify the applicability, NOx and SOx allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements. The RECLAIM program started with 392 NOx facilities in 1993, dropped to 281 facilities in 2011, with 275 facilities by end of the 2013 compliance year. Under the RECLAIM program, facilities are issued SOx and NOx annual allocations, also known as facility caps. The facility caps decline annually to reflect the levels of BARCT that were envisioned to be in place at the RECLAIM facilities. To meet their annual declining allocations, RECLAIM facilities have the flexibility of installing pollution control equipment, changing operations, or purchasing RECLAIM Trading Credits. It was envisioned that a BARCT analysis would be conducted periodically to capture the advancement in control technology and to assure that the RECLAIM program would achieve emission reductions equivalent to command and control approaches and as expeditiously as possible. Throughout the years, there have been a number of amendments to the RECLAIM rules, including BARCT reassessments for NOx in 2005 and SOx in 2010. As a result of the January 2005 amendment, NOx RTCs were reduced by 7.7 tpd, approximately 22.5%, across all 281 RECLAIM facilities. This reduction was implemented in phases: 4 tpd by 2007 and an additional 0.925 tpd in each of the following 4 years. Figures 1.1 – 1.3 show the historical trend of NOx emissions, RTC allocations, and RTC price for compliance years 1994 – 2013 reflecting the fact that the NOx reductions specified by the January 2005 amendment did not upset the market or cause RTC price spikes.

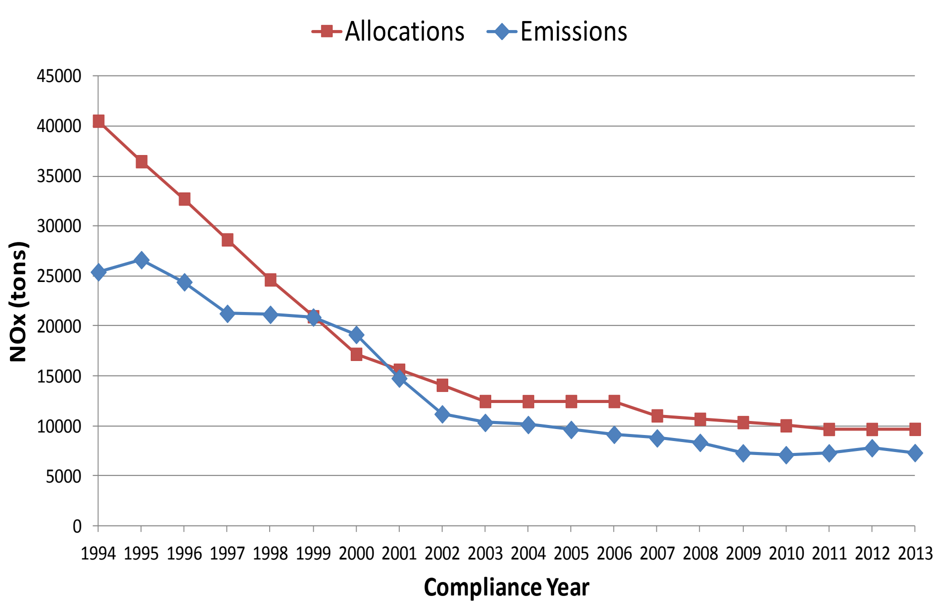


Figure 1. 1 – Audited Emissions and RTC Holdings

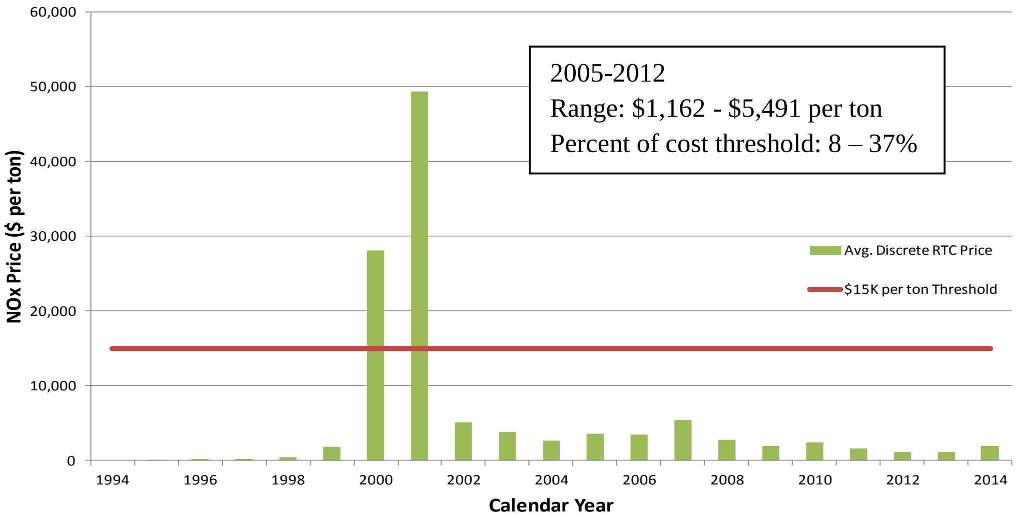


Figure 1.2 – NOx Discrete RTC Price versus Threshold

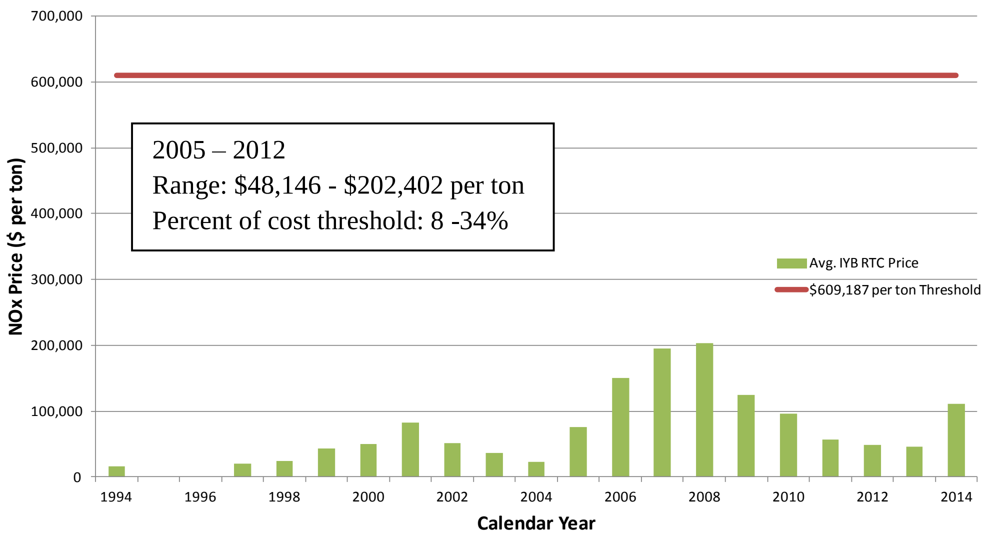


Figure 1.3 – NOx Infinite Year Block (IYB) RTC Price versus Threshold

According to the RECLAIM Annual Audit Reports, the vast majority of the RECLAIM facilities complied with their NOx RTC allocations and their aggregate RECLAIM NOx emissions remained below their NOx allocations for each compliance year since 2005. The audited annual NOx emissions, NOx RTCs allocated for the universe, and excess RTCs are summarized in Table 1.1. Data show that approximately 21–30% RTCs in each of the past 5 years were not used, approximately 5.45 tpd – 8.41 tpd.

Table 1. 1 – Audited Emissions, RTC Holdings and Unused RTCs from 2009-2013

Compliance Year	Audited emissions (tons)	RTC Holdings (tons)	Unused RTCs (tons)	Unused RTCs (%)
2009	7,306	10,377	3,071	30%
2010	7,121	10,053	2,932	29%
2011	7,302	9,690	2,388	25%
2012	7,691	9,689	1,988	21%
2013	7,326	9,699	2,373	24%

Reference: Table 3-2, page 3-4, Annual RECLAIM Audit Report for 2013 Compliance Year

NOx RECLAIM Facilities

There were 281 facilities in RECLAIM as of June 2011 and 275 by the end of compliance year 2013. These facilities either elected to enter the program or had NOx emissions greater than or equal to four tons per year in 1990 or any subsequent year. The distribution of the 20 tpd audited 2011 emissions and 26.5 tpd RTC allocations are shown in Figures 1.4 and 1.5.

The top 37 facilities emitted 17.10 tpd NOx in 2011, more than 85% of emissions. The NOx emissions from RECLAIM facilities are generated from a wide range of equipment, and the top NOx emitting sources at the 37 facilities are refinery coke calciners, refinery fluidized catalytic cracking units, refinery and non-refinery gas turbines, refinery boilers and heaters, glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces, internal combustion engines, and refinery sulfur recovery and tail gas incinerators. Cement kilns were the #1 emitting NOx source in 2008. The 2011 inventory did not include the cement kilns in the inventory due to the shutdown of the cement kilns in 2012, however staff did identify a new BARCT level for this operation.

Figure 1.5 shows the projected amount of RTC holdings by sector for 2020 without considering 2015 BARCT levels and the proposed amendments. Refineries hold over half of the RTC with the second most predominant RTC holding industry being power plants.

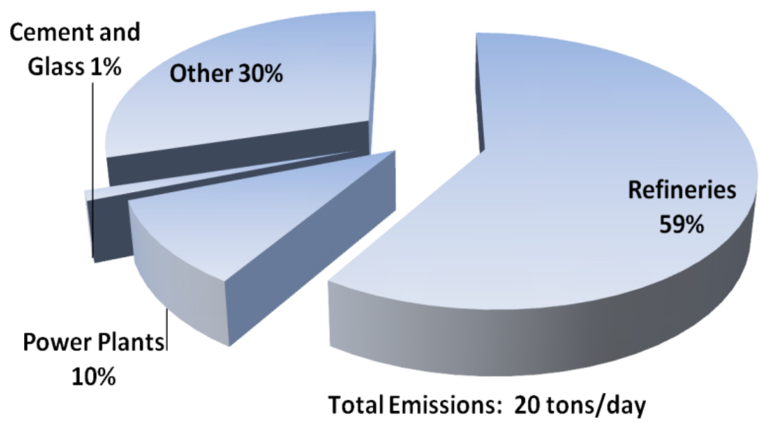


Figure 1. 4 – Distribution of 20 tpd NOx Emissions (End of Compliance Year 2011)

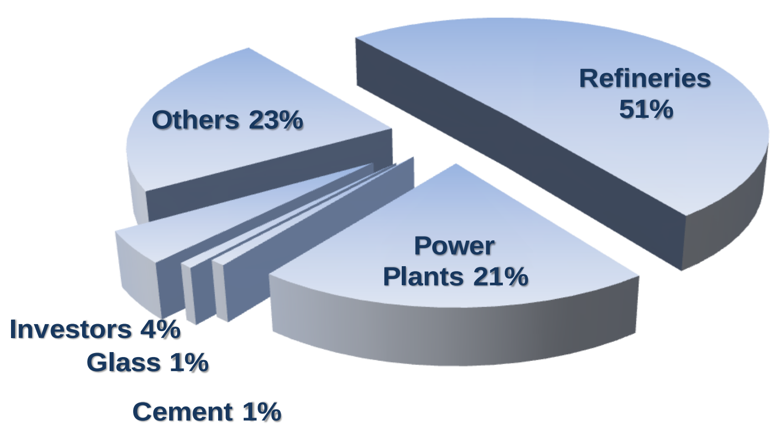


Figure 1. 5 – Distribution of 26.5 tpd RTC Holdings (End of Compliance Year 2020)

Chapter 2 – Facility Emissions and RTC Holdings

Projected Emissions and Emission Reductions

As stated in the 2012 AQMP and summarized in Table 2.1 below, NOx emissions from the RECLAIM facilities were projected to be about 27 tpd by 2023, representing 37% of the NOx emissions from stationary sources. Collectively, RECLAIM is the fourth largest source of NOx emissions in the Basin as shown in Table 2.2.

The 2012 AQMP estimated that in order to achieve the 8-hour ozone NAAQS, the region must reduce 65% of NOx emissions by 2023 (328 tpd x 0.65 = 213 tpd), and 75% of NOx by 2032 (328 tpd x 0.75 = 246 tpd). Since mobile sources emit over 80% of the regional NOx, the basin will require a broad deployment of zero and near zero emission technologies in 2023-2032 to achieve most of these needed reductions.

However, as shown in the 2012 AQMP, the current control measures for mobile and stationary sources provided less than 20 tpd of the total needed emission reductions. Thus, even though only 3-5 tpd of reductions for CMB-01 were estimated during the development of the 2012 AQMP, staff's analysis of BARCT, projected growth, and the NOx co-benefits from energy efficiency projects show that additional reductions from RECLAIM NOx sources are possible. Based on staff's current estimates, the RECLAIM program can contribute up to 14 tpd additional NOx emissions reductions by 2023.

Table 2. 1 - Annual Average Emissions (tpd) by Major Source Category (2023 Base Year)

Source Category	NOx
Stationary Sources	
Fuel Combustion (non-RECLAIM)	27
Waste Disposal	2
Cleaning and Surface Coatings	0
Petroleum Production and Marketing	0
Industrial Processes	0
Solvent Evaporation	
Consumer Products	0
Architectural Coatings	0
Others	0
Misc. Processes	17
RECLAIM Sources	**27**
Total Stationary Sources	**73**
Total Mobile Sources	**255**
TOTAL	**328**

Reference: Table 3-6A, 2012 South Coast AQMP

Table 2. 2 - Top Ten Ranking of NOx Emissions from Highest to Lowest (2023 Base Year)

Rank	Sources
1	Heavy-Duty Diesel Trucks
2	Off-Road Equipment
3	Ships & Commercial Boats
4	NOx RECLAIM
5	Locomotives
6	Aircraft
7	Residential Fuel Combustion
8	Heavy-Duty Gasoline Trucks
9	Passenger Cars
10	Light-Duty Trucks

Reference: Table 3-10 of the 2012 South Coast AQMP

Audited Facility Emissions and RTC Allocations

The 281 facilities, as of June 2011, emitted about 20 tpd NOx in 2011 and 20.7 tpd NOx when the power plants' emissions in 2012 were used instead of their 2011 emissions. Table 2.3 below lists the top 37 emitting facilities that contributed 17.10 tpd NOx emissions in 2011, more than 85% of the emissions from the entire NOx RECLAIM universe. The cement facility, the #1 emitting NOx facility from 2008 to 2010, was temporarily shut-down in 2011.

At the beginning of the RECLAIM program, the NOx RECLAIM universe was granted 40,534 tons per year (111 tpd) RTCs. This original amount of RTCs gradually dropped to a level of 12,486 tons per year (34.2 tpd) in 2005. In 2005, the SCAQMD conducted a BARCT re-assessment that resulted in a cumulative RTC reduction of 7.7 tpd that was fully implemented in 2011. For compliance year 2011 and beyond, the RTC holdings for the NOx universe remain at a constant level of 9,677 tons per year (26.5 tpd).

Table 2. 3 - NOx Audited Emissions (2011 Compliance Year)

			2011 Emissions (lbs)	2011 Emissions (tpd)
1	800089	EXXONMOBIL OIL CORPORATION	1,602,233	2.19
2	800030	CHEVRON PRODUCTS CO.	1,425,393	1.95
3	131003	BP WEST COAST PROD.LLC BP CARSON REF.	1,231,852	1.69
4	800436	TESORO REFINING AND MARKETING CO, LLC	1,171,965	1.61
5	171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1,143,902	1.57
6	171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	673,652	0.92
7	800026	ULTRAMAR INC (NSR USE ONLY)	534,363	0.73
8	131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	407,394	0.56
9	800183	PARAMOUNT PETR CORP (EIS USE)	104,249	0.14
10	151798	TESORO REFINING AND MARKETING CO, LLC	93,488	0.13
		Total Refineries		**11.49**
1	46268	CALIFORNIA STEEL INDUSTRIES INC	464,990	0.64
2	800128	SO CAL GAS CO (EIS USE)	461,243	0.63
3	166073	BETA OFFSHORE	391,977	0.54
4	171960	TIN, INC. DBA INTERNATIONAL PAPER	327,637	0.45
5	18931	TAMCO	226,012	0.31
6	800074	LA CITY, DWP HAYNES GENERATING STATION	205,022	0.28
7	160437	SOUTHERN CALIFORNIA EDISON	204,132	0.28
8	800193	LA CITY, DWP VALLEY GENERATING STATION	166,413	0.23
9	4242	SAN DIEGO GAS & ELECTRIC	142,751	0.20
10	4477	SO CAL EDISON CO	137,290	0.19
11	7427	OWENS-BROCKWAY GLASS CONTAINER INC	135,486	0.19
12	119907	BERRY PETROLEUM COMPANY	131,857	0.18
13	129816	INLAND EMPIRE ENERGY CENTER, LLC	105,857	0.15
14	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	103,988	0.14
15	115389	AES HUNTINGTON BEACH, LLC	98,993	0.14
16	51620	WHEELABRATOR NORWALK ENERGY CO INC	89,025	0.12
17	5973	SO CAL GAS CO	88,258	0.12
18	11435	PQ CORPORATION	81,270	0.11
19	115394	AES ALAMITOS, LLC	80,929	0.11
20	800335	LA CITY, DEPT OF AIRPORTS	73,245	0.10
21	129497	THUMS LONG BEACH CO	66,364	0.09
22	124838	EXIDE TECHNOLOGIES	62,824	0.09
23	15504	SCHLOSSER FORGE COMPANY	52,331	0.07
24	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49,983	0.07
25	800330	THUMS LONG BEACH	49,657	0.07
26	114801	RHODIA INC.	48,878	0.07
27	22911	CARLTON FORGE WORKS	48,839	0.07
		Total non-refineries		**5.61**
		Total for top 37 emitting facilities		**17.10**

Major NOx Sources at Top Emitting Facilities

RECLAIM Rule 2012 establishes the requirements for monitoring, reporting and recordkeeping of NOx emissions under the RECLAIM program and classifies the NOx emitting equipment at the RECLAIM facilities into three categories: major NOx sources, large NOx sources, and NOx process units. RECLAIM facilities are required to monitor the emissions for each major NOx source with a Continuous Emissions Monitoring System (CEMS) and report the emissions electronically on a daily basis via a remote terminal unit to the SCAQMD Central Station. The emissions for each large source are calculated based on fuel usage or exhaust gaseous flow rates and reported electronically on a monthly basis to the SCAQMD Central Station. The emissions from all process units are reported on a quarterly basis.

Table 2.4 shows that major NOx sources contributed 88% of the NOx emissions from the NOx RECLAIM universe; large NOx sources and process units generated only 12% of the NOx RECLAIM emissions. Thus, staff focused on the major NOx sources at the top 37 emitting facilities to evaluate potential BARCT and emission reductions.

The major NOx sources at the top 37 emitting RECLAIM facilities subject to new 2015 BARCT analysis are refinery fluid catalytic cracking units, refinery boilers and heaters >40 mmbtu/hr, refinery and non-refinery gas turbines, cement kilns, glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces >150 mmbtu/hr, refinery sulfur recovery and tail gas incinerators, and internal combustion engines.

Table 2. 4 - NOx Emissions per Source Classification

Source Categories	NOx (tons per day)	Number of Equipment	Percentage of Emissions
Major NOx Sources	17.5	415	88%
Large sources and Process Units	2.6	>1000	12%
Total	**20.0**		**100%**

Chapter 3 – 2015 Proposed BARCT and Emission Reductions

Previous BARCT Determinations

At the inception of the RECLAIM program, the SCAQMD established the NOx starting allocations in 1994 and ending allocations in 2000 based on the starting and ending emissions factors listed in Table 1 of Rule 2002 – *Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)*. For the 2003 ending allocations, the SCAQMD adjusted the 2000 ending allocations to be equal to the 1991 AQMP projected inventory for RECLAIM sources in 2003. The 2005 ending allocations were set equal to the 2003 ending allocations. In 2005, the SCAQMD conducted a BARCT re-assessment, and reduced the allocations of the RECLAIM universe by 7.7 tpd implemented by 2011. Table 3 of Rule 2002 was added to record the 2005 BARCT levels. The BARCT levels were kept at the 2000 ending emission factors as shown in Table 2 of Rule 2002 for individual equipment categories where improved control technologies were not yet deemed applicable or cost-effective in the 2005 BARCT assessment.

Proposed 2015 BARCT and Emission Reductions

Staff is proposing the BARCT levels tabulated in Table 3.1 and estimating that these 2015 BARCT levels will provide about 8.79 tpd in NOx emission reductions (6.02 tpd for refinery sector and 2.77 tpd for non-refinery sector) beyond what could be achieved by the 2005 BARCT levels for each category of major emitting sources at the top emitting facilities. Further discussions of NOx control technologies, proposed BARCT levels, estimated emission reductions, costs and cost effectiveness values are discussed in Part I of this staff report for the refinery sector and Part II for the non-refinery sector. The RTC reductions are discussed separately in Chapter 5 and Part III of this staff report.

Part I – BARCT Analyses for Refinery Sector:

Appendix A and Appendix F	Fluid Catalytic Cracking Units
Appendix B and Appendix G	Boilers and Heaters, >40-100 mmbtu/hr
Appendix C and Appendix J	Refinery Gas Turbines
Appendix D and Appendix I	Coke Calciner
Appendix E and Appendix H	Sulfur Recovery Units Tail Gas Incinerators

Part II – BARCT Analyses for Non-Refinery Sector:

Appendix M	Cement Kilns
Appendix N	Container Glass Melting Furnaces
Appendix O	Sodium Silicate Furnace
Appendix P	Metal Melting Furnaces > 150 mmbtu/hr
Appendix Q	Non-Refinery Gas Turbines

Appendix R	Non-Refinery, Non-Power Plant Internal Combustion Engines
Appendix S	Non-Refinery Boilers > 40 mmbtu/hr

Table 3. 1 - 2015 Proposed BARCT Levels and Emission Reductions

Refinery Sector	2015 BARCT Level	Emission Reductions (tpd)
Fluid Catalytic Cracking Units	2 ppmv at 3% O2	0.43
Boilers and Heaters >40 mmbtu/hr	2 ppmv or 0.002 lb/mmbtu	0.96
Gas Turbines	2 ppm at 15% O2	4.14
Coke Calciner	10 ppmv at 3% O2	0.17
Sulfur Recovery Units Tail Gas Incinerators	2 ppmv at 3% O2 or 95% reduction	0.32
	Total	**6.02**
Non-refinery Sector	**2015 BARCT Level**	**Emission Reductions (tpd)**
Cement Kilns	0.5 lb/ton clinker	1.32 (note)
Container Glass Melting Furnaces	80% reduction	0.24
Sodium Silicate Furnace	80% reduction	0.09
Heat Treating Furnaces >150 mmbtu/hr	9 ppmv at 3% O2	0.56
Gas Turbines (non-OCS)	2 ppmv at 15% O2	1.04
ICEs (non-OCS)	11 ppmv at 15% O2	0.84
	Total	**2.77**

Note: The emission reductions for cement kilns were not included in the total 2.77 tpd emission reductions because the cement kilns were not in operation in 2011 time frame.

Co-Benefits of Energy Efficiency Projects

For the refinery sector, in addition to the 6.02 tpd emission reductions shown in Table 3.1, there are about 0.6 to 0.7 tpd NOx emission reductions that are expected to have occurred concurrently with the energy efficiency projects to reduce greenhouse gases as shown in Table 3.2. According to CARB, these co-benefits reductions were not yet included in the baseline and staff did not include the co-benefits in this proposal. See Appendix K for further details.

Table 3. 2 - Co-Benefits of Emission Reductions for Energy Efficiency Projects

Projects	Emission Reductions (tpd)
Completed and ongoing (2007-2011)	0.6
Scheduled	0.05
Under investigation	0.07 – 0.08
Total	**0.7**

Chapter 4 – Costs and Cost Effectiveness

Staff's Preliminary Estimates

Staff preliminary analyses as of December 2014 for costs and cost effectiveness are discussed in Part I, Appendices A – E, for the refinery sector and Part II, Appendices M – S, for the non-refinery sector, respectively. A summary of the methods used for costs and cost effectiveness analyses and the results of these detailed analyses are provided in this Chapter.

The Present Worth Values (PWV) of a control device are the total costs to install and operate the control device estimated at the present currency value. The PWV consists of the Total Installed Costs (TIC) and Annual Operating Costs (AC) during the entire economic life of the control equipment using the Discounted Cash Flow (DCF) Method as follows:

$$PWV = TIC + (15.62 \times AC)$$

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
15.62 = a factor to estimate the cumulative annual operating costs during a 25-year life of a control device

The incremental cost effectiveness value of a control device is estimated as follows:

$$CE_{\text{incremental}} = (PWV_{2015\ BARCT} - PWV_{2005\ BARCT}) / (ER_{2015\ BARCT} - ER_{2005\ BARCT}) / 25\ \text{yrs} / 365\ \text{days}$$

Where:

$CE_{\text{incremental}}$ = Incremental Cost Effectiveness, $/ton
$PWV_{2015\ BARCT}$ - $PWV_{2005\ BARCT}$ = Incremental costs to achieve additional control to meet the 2015 BARCT level from the 2005 BARCT level
$ER_{2015\ BARCT}$ - $ER_{2005\ BARCT}$ = Incremental emission reductions to achieve the 2015 BARCT level from the 2005 BARCT level

The incremental costs and cost effectiveness were calculated based on the 2011-2012 baseline emissions and the DCF method. Staff also presented the cost effectiveness estimated with the Levelized Cash Flow (LCF) method. In the cost effectiveness analysis using the DCF method, staff used a cutoff level of $50,000 per ton. The $50,000 per ton cutoff is based on the policy developed during the 2008 – 2010 SOx RECLAIM rule amendment that was adopted by the District Governing Board. The results of staff's preliminary estimates in 2014 for PWVs and cost effectiveness values are summarized in Tables 4.1 and 4.2; and the revised estimates are summarized in Tables 4.3 and 4.4.

Consultants' Estimates and Staff's Review

In September-December 2014, SCAQMD contracted with two consultants, NEC and ETS, to conduct independent studies on costs and cost effectiveness. The consultants' reports are included as separate documents. Table 4.1 below shows a comparison between staff's and NEC's estimates for the refinery sector, and Table 4.2 shows a comparison between staff's and ETS's estimates for the non-refinery sector.

Refinery Sector

For the refinery sector, as shown in Table 4.1, NEC was in agreement with staff on the proposed BARCT levels of 2 ppmv recommended for gas turbines, FCCUs, boilers/heaters, and SRU/TG incinerators. For the refinery coke calciner, NEC recommended a BARCT level of 5 – 10 ppmv instead of 2 ppmv previously recommended by staff. Staff agreed with NEC's recommendation and changed the assumption to 10 ppmv BARCT level for the coke calciner. However, after extensive discussion, staff used different approaches than NEC to estimate the SCR costs for FCCUs, boilers/heaters and SRU/TG incinerators. Please refer to Part I, Appendix F – J, for further discussions. Table 4.3 shows the revised ranges of PWVs and cost effectiveness values for the refinery sector.

Table 4. 1 - BARCT Levels, Costs and Cost Effectiveness Estimates for Refinery Sector (December 2014)

Equipment Category	Proposed 2014 BARCT	AQMD's Estimates		Estimates using NEC's Information		Incremental Cost Effectiveness
		Reductions (tpd)	PWVs ($M)	Reductions (tpd)	PWVs ($M)	$ per ton NOx Reduced
Gas Turbines	2 ppmv	4.14	97.7	4.14	52.7	1K – 3K
FCCUs	2 ppmv	0.43	152	0.43	211	3K – 18K
Coke Calciner	5 ppmv	0.21 (1)	22 - 61	0.17 (2)	39.5	11K – 25K
Boilers/Heaters > 40 mmbtu/hr	2 ppmv	1.05	254.5	0.61	162	27K – 29K
SRU/TG Incinerators	2 ppmv	0.35	49 - 68	0.32	120	15K – 48K
Total		**6.2**	**575 - 633**	**5.7**	**585**	**7K-12K (3)**

Note: 1) Based on 5 ppmv BARCT, 2) Based on 10 ppmv BARCT, 3) Weighted average by NOx reductions

Non-Refinery Sector

For the non-refinery sector, ETS was in agreement on the proposed BARCT levels that staff recommended for all categories. ETS's estimated costs and incremental costs were slightly higher than staff's estimates as shown in Table 4.2. Table 4.4 shows the revised ranges of PWVs and cost effectiveness values for the non-refinery sector.

Table 4. 2 – BARCT Levels, Costs and Cost Effectiveness Estimates for Non-Refinery Sector (December 2014)

Source Category	Proposed 2014 BARCT	Emission Reductions (TPD)	SCAQMD PWV ($MM)	ETS PWV ($MM)	Incremental DCF CE ($/ton)
Cement Kilns	0.5 lb/ton clinker	1.32	34 – 107	36 – 112	3 – 10K
Container Glass	0.24 lb/ton pulled	0.24	4 – 14	6 – 15	3 – 7K
Sodium Silicate Furnace	1.28 lb/ton pulled	0.09	2.8 – 4.6	3 – 4.6	4 – 6K
Metal Heat Treating Furnaces >150 MMBTU/hr	9 ppm @3%O_2	0.56	8 – 10	8 – 10	3 – 3.8K
Gas Turbines	2 ppm @15%O_2 or 95% reduction	1.04	3 – 14	3 – 14	5 – 36K
ICEs	11 ppm @15%O_2	0.84	0.9 – 4	0.9 – 4	5 – 8K
Boilers >40 MMBTU/hr	No new BARCT	0	0	0	0
Total		**4.09**	**53 – 154**	**57 – 160**	**4K-15K****

*LCF ranges from $5,000-$57,000 per ton **weighted average by NOx reductions

Staff's Recommendations

Refinery Sector

Staff's revised recommendations for the refinery sector are tabulated in Table 4.3. Please refer to Part I, Appendices A-J for additional information.

Table 4. 3 - Staff's Revised Recommendation for Refinery Sector (May 2015)

	2015 BARCT	Incremental Reductions (tpd)	PWVs ($M)	Incremental Cost Effectiveness ($K/ton DCF)	Note
FCCUs	2 ppmv	0.43	152 – 391	3 – 13	1
Gas Turbines	2 ppmv	4.14	53 – 98	1 – 3	2
Boilers/Heaters >40 mmbtu/hr	2 ppmv	0.96	242	28	3
Coke Calciner	10 ppmv	0.17	40 - 91	19 – 25	4
SRU/TG Incinerators	2 ppmv	0.32	83 - 106	28 – 40	5
Total		**6.02**	**570 – 928**	**10 – 17**	6

Notes:

1) See Appendix A. The PWV of $152M are for the case where all 5 refineries would install SCRs. The PWV of $391 M are for the case where SCRs would be installed at Ref 5 and 6 and LoTOx and scrubbers at Ref 4, 7 and 9 to reduce both NOx and SOx.
2) See Appendix C. The PWV of $53 M was estimated by NEC for adding catalysts to all SCRs. The PWV of $98 M was derived by SCAQMD for adding catalysts to Ref 1's SCRs and new SCRs to Ref 4 - 7.
3) See Appendix B.
4) See Appendix D. The PWV of $40M was estimated by NEC for LoTOx technology and $91 M was staff's estimates for Tri-Mer technology
5) See Appendix E. The PWV of $83 M was for SCRs and $106 M for LoTOx applications
6) Weighted average by NOx reductions

Non-Refinery Sector

Table 4.4 tabulates staff's current recommendations for the non-refinery sector. Please refer to Part II, Appendices M-R for further information.

Table 4. 4 - Staff's Recommendation for Non-Refinery Sector (May 2015)

	2015 BARCT	Incremental Reductions (tpd)	PWVs ($M)	Incremental Cost Effectiveness ($K/ton DCF)	Note
Cement Kilns	0.5 lb/ton clinker	1.32	34 - 112	3 – 10	1
Container Glass Melting Furnaces	0.24 lb/ton glass pulled	0.24	4 – 15	3 – 7	2
Sodium Silicate Furnace	1.28 lb/ton glass pulled	0.09	2.8 – 4.6	4 – 6	3
Metal Heat Treating Furnace > 150 mmbtu/hr	9 ppmv at 3% O2	0.56	8 – 10	3 – 3.8	4
Gas Turbines	2 ppmv at 3% O2	1.04	3 – 14	5 – 36	5
ICEs	11 ppmv at 15% O2	0.84	0.9 – 4	5 – 8	6
Total		**4.09**	**53 - 160**	**4 – 15**	7

Note:

1) Refer to Appendix M
2) Refer to Appendix N
3) Refer to Appendix O
4) Refer to Appendix P
5) Refer to Appendix Q
6) Refer to Appendix R
7) Weighted average by NOx reductions

Chapter 5 - RTC Reductions

Remaining Emissions

As discussed in the Public Process section, staff started the discussion with stakeholders since 2013 on the calculation method that would be used to estimate the RTC reductions. One of the parameters used in the calculation for the RTC reductions is the remaining emissions projected to 2023. The 2023 remaining emissions estimated by staff were first presented to the stakeholders in the January 22, 2014 Working Group Meeting. Staff later refined the numbers and presented them to the stakeholders in the July 31, 2014 and April 29, 2015 Working Group Meetings. The changes made are summarized below.

Refinery Sector

Table 5.1 tabulates the estimated 2023 remaining emissions for each NOx source category in the refinery sector. In 2014, staff estimated the total 2023 remaining emissions to be 2.56 tpd. In 2015, staff revised the number to 2.71 tpd as a result of the following changes:

- The BARCT level for coke calciner was changed from 2 ppmv to 10 ppmv. As a result, the remaining emissions for coke calciner increased to 0.08 tpd

- The costs of control for boilers/heaters and SRU/TG incinerators were revised to be higher. As a result, the cost effectiveness for several boilers/heaters and one incinerator became higher than the policy threshold of $50,000 per ton, and these units were excluded from the analysis. The remaining emissions for the boilers/heaters >40 mmbtu/hr increased to 0.83 tpd, and the remaining emissions for the SRU/TG incinerators increased to 0.11 tpd.

Table 5. 1 - Remaining Emissions for Refinery Sector (May 2015)

	Total No of Units	2011 Emissions (tpd)	2000/2005 BARCT	2011 Emissions at 2000/2005 BARCT (tpd)	2015 BARCT	2011 Emissions at 2015 BARCT (tpd)	2023 Emission Reductions Beyond 2000/2005 BARCT (tpd)	2023 Emission at 2015 BARCT with GF = 1 (tpd)
FCCUs/CO Boilers	8	1.08	85% control	0.60	2 ppmv	0.17	0.43	0.17
Turbines/Duct Burners	21	1.33	62.27 lbs/mmcft	4.86	2 ppmv	0.72	4.14	0.72
Coke Calciner	2	0.55	30 ppmv	0.25	10 ppmv	0.08	0.17	0.08
SRU/TG Incinerators	17	0.43	RV	0.43	2 ppmv (or 95% control)	0.11	0.32	0.11
Boilers/Heaters > 110 mmbtu/hr	73	4.88	5 ppmv	0.82	2 ppmv	0.38	0.44	0.38
Boilers/Heaters >40-110 mmbtu/hr	69	2.00	25 ppmv	0.97	2 ppmv	0.45	0.52	0.45
Boliers/Heaters 20-40 mmbtu/hr	52	0.45	9 ppmv	0.10	n/a	0.10	0.00	0.10
Boilers/Heaters <20 mmbtu/hr	18	0.06	12 ppmv	0.02	n/a	0.02	0.00	0.02
Other Major/Large Sources	5	0.11	n/a	0.10	n/a	0.10	0.00	0.10
Other Process Units	n/a	0.60	n/a	0.60	n/a	0.60	0.00	0.60
Total	**265**	**11.50**		**8.76**		**2.74**	**6.02**	**2.71**

Non-Refinery Sector

Table 5.2 tabulates the estimated 2023 remaining emissions for each NOx source category in the non-refinery sector. In 2014, staff estimated the 2023 remaining emissions for the refinery sector to be 8.77 tpd. In 2015, staff revised the number to 7.47 tpd as a result of the following changes:

- The baseline for power plants was changed from 2011 to 2012. The 2011 and 2012 baseline emissions were 1.45 tpd and 2.50 tpd, respectively. Staff also used either the BACT level or the level stated in the permit operating conditions to estimate the emission reductions beyond the levels that could be achieved by the 2005 BARCT. In addition, staff used the most recent growth factor of 0.868 to estimate the remaining emissions for the power plants. As a result of these changes, the 2023 remaining emissions for power plants were changed to 2.04 tpd.

- The remaining emissions from non-power plants were changed to 1.37 tpd; and

- The remaining emissions from other sources were changed to 4.06 tpd.

Table 5. 2 - Remaining Emissions for Non Refinery Sector (May 2015)

POWER PLANTS*	# of Facilities	2012 Emissions (tpd)	2000/2005 BARCT	2012 Emissions at BARCT/BACT (tpd)	2015 BARCT	2012 Emissions at 2015 BARCT (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	Growth Factor	2023 Emissions at 2015 BARCT (tpd)
TOTAL	30	2.50	P/O or BACT level	2.35	No new BARCT	2.35	0	0.8683	2.04
NON-POWER PLANTS	# of Units	2011 Emissions (tpd)	2000/2005 BARCT	2011 Emissions at 2000/2005 BARCT (tpd)	2015 BARCT	2011 Emissions at 2015 BARCT (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	Growth Factor	2023 Emissions at 2015 BARCT (tpd)
Boilers	16	0.08	9-12 ppm	0.07	No new BARCT	0.07	0	0.96	0.07
Heaters	3	0.01	60 ppm	0.01	No new BARCT	0.01	0	0.93	0.01
Furnaces >150 MMBTU/hr	2	0.49	45 ppm	0.70	9 ppm	0.14	0.56	0.93	0.13
Furnaces	10	0.31	45 ppm	0.31	No new BARCT	0.31	0	0.93	0.29
Glass Melting Furnaces	2	0.30	1.2 lb/ton	0.30	80% Reduction	0.06	0.24	1.18	0.07
Sodium Silicate Furnace	1	0.11	6.4 lb/ton	0.11	80% Reduction	0.02	0.09	1.21	0.02
Gas Turbines (non-OCS)	14	1.43	61.45 lb/mmcf	1.24	2 ppm	0.21	1.04	1.10	0.23
Gas Turbines (OCS)	6	0.49	61.45 lb/mmcf	0.12	No new BARCT	0.12	0	1.46	0.18
ICEs (non-OCS)	25	0.35	217.36 lb/mmcf	1.05	11 ppm	0.21	0.84	1.03	0.22
ICEs (OCS)	6	0.03	217.36 lb/mmcf	0.11	No new BARCT	0.11	0	1.46	0.16
*Cement Kilns***	*2*	*1.61*	*2.73 lb/ton*	*1.61*	*0.5 lb/ton*	*0.32*	*1.29*	*0.9*	*0.29*
TOTAL	87	3.60		4.02		1.26	2.77		1.37
Other Sources***		3.12		3.12		3.12			4.06
TOTAL NON-REFINERY		9.22		9.49		6.73	2.77		7.47

*This includes all power plants in RECLAIM. Calendar year 2012 AER reported fuel usage was used to calculate emissions at BARCT/BACT level.

**CPCC's emissions and emission reductions have NOT been included in the totals, this facility did not have any emissions in CY2011. CY2008 emissions were used to calculate the emission reductions.

***Includes Non-Refinery, Non-Power Plant Process Units in the Top 37 and all other sources outside the Top 37.

Calculation Method for RTC Reductions

The RTC reductions are calculated as follows:

RTC Reductions = RTC Holdings – (Remaining Emissions x Compliance Margin)

Where

RTC Holdings = 26.5 tpd
Remaining Emissions = ($R_{Refinery}$ + $R_{Non\text{-}Refinery}$ + $R_{Adjustment}$)
$R_{Refinery}$ = Remaining emissions for refinery sector x Growth Factor
$R_{Non\ Refinery}$ = Remaining emissions for non-refinery sector x Growth Factors
$R_{Adjustment}$ = Potential adjustments set aside for new power plants
Compliance margin = 10% as provided in the previous RECLAIM amendments

An example shown below was presented at the April 29, 2015 Working Group Meeting:

$R_{Refinery}$ = 2.71 tpd including growth factor of 1 as shown in Table 5-1
$R_{Non\ Refinery}$ = 2.77 tpd including growth factor of 1 as shown in Table 5-2
$R_{Adjustment}$ = 0.07 tpd potential set aside for new power plants due to SONGS shutdown and 0.29 and 0.10 for CPCC and other shutdown facilities
RTC Reductions = 26.5 – ([(2.71 + 7.47 + 0.07) x 1.1] + (0.29 + 0.10))
= 26.5 - 11.67 = 14.85 tpd

Adjustment Account for Power Generating Facilities

Staff has received input from several power generating operators that have concerns with concurrent compliance with the RTC allocation shave and the new source review (NSR) holding requirements per Rule 2005. New facilities that entered into RECLAIM after October 15, 1993 must hold RTCs for all of their equipment at the permitted potential to emit (PTE) level for every compliance year. Power producing facilities often operate at a capacity factor well below the PTE level during any given compliance year. The combustion equipment for these facilities is also already at the BARCT or BACT emission level. These facilities would be shaved and be subject to complying with the NSR holding requirements as well as their annual emission reconciliation requirements.

Staff has proposed the creation of an adjustment account to address the NSR holding requirements programmatically for all power producing facilities, instead of at the facility level. This adjustment account would eliminate the individual facility NSR hold requirements and would be comprised of a portion of the shaved RTCs from these facilities as discrete credits. Power producing facilities would be allowed to access this account to offset emissions (rather than just satisfy NSR holding requirements) if the governor of California declares a state of emergency regarding reliable energy supply. The size of the adjustment account has not been finalized at this time but would be equivalent to the RTCs shaved from the affected power plants. Staff is currently soliciting comments from the regulated community, primarily to ensure that the shave and the adjustment account do not result in a situation where there would be a large shortage of RTCs in the event of a power emergency.

Staff's Proposal and CEQA Alternatives

Staff has considered seven approaches to determine the RTC reductions and the most appropriate shave distribution to protect the environment, satisfy state and federal CAA requirements and AQMP commitments, and at the same time, allow for economic growth and safeguards for the functioning of the RECLAIM program.

Table 5.3 summarizes staff's current proposal. Staff is proposing a NOx RTC shave of 14 tpd rather than the 14.85 tpd calculated above. The 0.85 tpd difference roughly accounts for comments received from stakeholders regarding remaining uncertainties in the BARCT analysis, and thus provides an additional compliance margin. Staff is currently proposing that the 14 tpd RTC reductions be distributed to 65 facilities and investors that collectively hold about 90% of the 26.5 tpd RTCs. The 65 affected facilities include 9 major refineries, 30 power plants, and 26 other top emitting facilities as shown in Table 5.5. Staff is proposing not to shave the remaining 210 facilities that hold only 10% of the 26.5 tpd RTCs because there was no new BARCT identified for the types of equipment and operations there. The remaining six approaches to determine the RTC reductions as shown in Table 5.4 will be analyzed as project alternatives in the CEQA analysis. For further information, please refer to Part III, Appendix U of this staff report.

Staff is proposing the following implementation schedule:

2016: 4 tons per day
2018: 2 tons per day
2019: 2 tons per day
2020: 2 tons per day
2021: 2 tons per day
2022: 2 tons per day

As shown in Table 1-1 of Chapter 1, in the past five years from 2009-2013, the unused RTCs in the NOX RECLAIM program ranged from 5.45 to 8.41 tpd, and thus staff is proposing a reasonable initial 4 tpd RTC reduction in 2016. Additional BARCT implementation will take about 2 – 4 years for planning, permitting, and construction, and staff is proposing that the remaining shave of 10 tpd take place between 2018 and 2022. Staff is seeking input from the stakeholders on the schedule for RTC reductions.

Table 5. 3 - Staff’s Proposal - Affected Facilities and Percent Shave (July 2015)

	Major Refineries and Investors	Non-Major Refineries or Other Facilities	Power Plants	Bottom 10% of RTC Holders	Total
No of facilities	9	26	30	210	275
Current RTCs	14.44	9.41		2.65	26.5
RTC Reductions	9.61	4.39		0	**<u>14.0</u>**
Remaining RTCs	4.83	5.02		2.65	12.50
Percent Shave	9.61/14.44 = 67%	4.39/9.41 = 47%		0%	

Note that investors are counted as one facility and grouped with the refineries.

Table 5. 4 - Alternatives for CEQA Analysis (July 2015)

	Alternative	Major Refineries + Investors	Non-Major Refineries/ Facilities	Power Plants	Bottom 10% of RTC Holders
1	Shave 14 tpd uniformly across all 275 facilities	53%	53%	53%	53%
2	Shave 15 tpd (w/o 10% compliance margin) uniformly across all 275 facilities	60%	60%	60%	60%
3	Shave 8.79 tpd (the difference in emission reductions between previous BARCT and 2015 BARCT) uniformly across all 275 facilities	33%	33%	33%	33%
4	No project	0%	0%	0%	0%
5	Shave 14 tpd weighted by BARCT reduction contribution and distributed to all 275 facilities	67%	36%	36%	36%
6	Shave 14 tpd distributed to top 57 facilities and investors. The shave will not affect 218 remaining facilities.	67% (9 facilities)	47% (30 facilities)	47% (18 facilities)	0%

Table 5. 5 - List of 65 Affected Facilities and Investors

Facility ID	Name
800030	CHEVRON PRODUCTS CO.
800089	EXXONMOBIL OIL CORPORATION
174655	TESORO REFINING & MARKETING CO, LLC
800436	TESORO REFINING AND MARKETING CO, LLC
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL
800026	ULTRAMAR INC
115394	AES ALAMITOS, LLC
115663	EL SEGUNDO POWER, LLC
800074	LA CITY, DWP HAYNES GENERATING STATION
800128	SO CAL GAS CO
800075	LA CITY, DWP SCATTERGOOD GENERATING STN
46268	CALIFORNIA STEEL INDUSTRIES INC
115536	AES REDONDO BEACH, LLC
160437	SOUTHERN CALIFORNIA EDISON
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY
174591	TESORO REF & MKTG CO LLC,CALCINER
115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST
152707	CPV SENTINEL LLC
169754	OXY USA INC
115389	AES HUNTINGTON BEACH, LLC
7427	OWENS-BROCKWAY GLASS CONTAINER INC
18931	TAMCO
4477	SO CAL EDISON CO
800183	PARAMOUNT PETR CORP
43201	SNOW SUMMIT INC
172005	NEW- INDY ONTARIO, LLC
146536	WALNUT CREEK ENERGY, LLC
800189	DISNEYLAND RESORT
156741	HARBOR COGENERATION CO, LLC
151798	TESORO REFINING AND MARKETING CO, LLC
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA
11435	PQ CORPORATION
4242	SAN DIEGO GAS & ELECTRIC
115314	LONG BEACH GENERATION, LLC
17953	PACIFIC CLAY PRODUCTS INC
153992	CANYON POWER PLANT
800127	SO CAL GAS CO
800193	LA CITY, DWP VALLEY GENERATING STATION
119907	BERRY PETROLEUM COMPANY
25638	BURBANK CITY, BURBANK WATER & POWER
124838	EXIDE TECHNOLOGIES
51620	WHEELABRATOR NORWALK ENERGY CO INC
5973	SO CAL GAS CO
800168	PASADENA CITY, DWP
3968	TABC, INC
8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI
155474	BICENT (CALIFORNIA) MALBURG LLC
800181	CALIFORNIA PORTLAND CEMENT CO
166073	BETA OFFSHORE

114801	SOLVAY USA, INC.
800153	US GOVT, NAVY DEPT LB SHIPYARD
8547	QUEMETCO INC
1073	BORAL ROOFING LLC
800170	LA CITY, DWP HARBOR GENERATING STATION
172077	CITY OF COLTON
139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT
129810	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT
164204	CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT
56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION
14502	VERNON CITY, LIGHT & POWER DEPT
129816	INLAND EMPIRE ENERGY CENTER, LLC
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC
132191	PURENERGY OPERATING SERVICES, LLC
132192	PURENERGY OPERATING SERVICES, LLC
167432	EDISON MISSION HUNTINGTON BEACH, LLC
	INVESTORS

Chapter 6 – Summary of the Proposed Changes in Rule Language and Draft Program Environmental Assessment

Rule 2002 (f)(1) – BARCT Proposed Levels and RTC Reductions

The staff proposal of the new BARCT levels for the refinery and non-refinery sectors are summarized in Table 6 of Rule 2002.

The staff proposal calls for a programmatic reduction of 14 tons per day RTC holdings in two phases. Four tons per day would be reduced in 2016 and the remainder would be reduced in equal increments from 2018 to 2022. There would be no reductions proposed for the year 2017. These reductions are reflected in subparagraphs (f)(1)(B) and (f)(1)(C). Subparagraph (f)(1)(B) includes all of Major Refineries and Investors. The Major Refineries are listed in Table 7 of Rule 2002. Subparagraph (f)(1)(C) includes all other facilities subject to the reduction in NOx RTCs. These facilities are listed in Table 8 of Rule 2002.

The remaining NOx RTCs after a shave for any compliance year would be the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(B) multiplied by the RTC holdings (as of March 20, 2015) of all the Major Refineries listed in Table 7 plus the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(C) multiplied by the RTC holdings (as of March 20, 2015) of all the facilities listed in Table 8. Please see Appendix U for further explanations on how the factors in subparagraphs (f)(1)(B) and (C) were derived.

Since the RTC reductions specified in subparagraph (f)(1)(A) have been realized, the conversion of non-tradable/non-usable NOx RTCs to tradable/usable NOx RTCs is no longer applicable to the RTC reductions specified in this subparagraph. The tradable/usable NOx RTCs specified in subparagraph (f)(1)(A) would remain intact and used for calculating RTC reductions for facilities entering the RECLAIM program. However the same approach in converting adjustment factors previously specified in subparagraph (f)(1)(A) would now be applied to the RTC reductions specified in subparagraphs (f)(1)(B) and (f)(1)(C).

Rule 2002 (f)(4)and (f)(5) – Adjustment Account and State of Emergency Related to Power Producing Facilities

A new Power Producing facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. Staff is proposing to create an Adjustment Account that would be used for the purpose of complying with the NSR requirements specified in Rule 2005. These proposed requirements are specified in Rule 2002 paragraph (f)(4).

Staff is also proposing in paragraph (f)(5) that during a State of Emergency as declared by the Governor, the Executive Officer will allow Power Producing Facilities access to the Adjustment Account RTCs for the purpose of compliance with the annual emissions. The available RTCs would be limited to those that are in excess of those specified for use in paragraph (f)(4). The amount and distribution of the RTCs will be determined by the Executive Officer based on the impact that the State of Emergency has on the RECLAIM program.

It is estimated that the needed RTCs in the Adjustment Account for the new Power Producing facilities would be 1 to 1 ½ tons per day. These Adjustment Account RTCs would be derived from the proposed programmatic 14 tons per day in NOx reductions.

Rule 2002 (i) – RTC Reduction Exemption

Facilities seeking an exemption from the proposed RECLAIM shave as specified in subdivision (i) would be required to meet the new BARCT emission factors as shown in Table 6 of Rule 2002. Consequently, the shave exemption would be based on the more stringent emission factor specified in Tables 3 (factors generated in the January 7, 2005 amendment to Rule 2002) and 6. Minor revisions in several subparagraphs of Rule 2002 (i) are proposed. Please see Appendix X for further explanations.

Rule 2005 – Requirements for New Power Producing Facilities

Rule 2005 sets forth requirements for new or modified equipment or processes at RECLAIM facilities. The purpose of the rule is to ensure that the RECLAIM program is equivalent to the federal and state NSR program requirements. One of the requirements is to ensure that the facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. For an RECLAIM facility existing prior to the the adoption of the RECLAIM program, the amendments made in June 3, 2011 required the RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but will not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocations plus non-tradable credits. However, a new RECLAIM facility will have to continue to hold adequate RTCs equal to the amount of emission increases at the beginning of each compliance year. Any excess RTCs cannot be sold until the end of the compliance year, or the applicable quarters if the facility has permit conditions to cap its emissions during each quarter, thus allowing sale of unused RTCs at the end of the quarter. To remedy this burdensome RTC holding requirement for new power producing facilities that cannot change their allowable NOx emissions in their Facility Permit staff is proposing an Adjustment Account described in Rules 2002(f)(4) and (5) above. Proposed changes in Rule 2005 would assure that the RTCs in the Adjustment Account would only be used the for the purpose of complying with the NSR requirements. Please see Appendix X for further explanations.

Other Administrative Amendments

Besides the changes described in Rule 2002 and 2005 described above, staff also proposes administrative amendments to Regulation XX to clarify the rule language and to ensure effective and consistent implementation of the RECLAIM program.

Rule 2002(b)(5) - 5-Year Limitation on Amending Annual Emission Reports

Some facilities entering the RECLAIM program have sought to amend their past AERs, which dated as far back as 1989, in ways that increase the initial SOx and/or NOx allocations previously determined pursuant to Rule 2002. The longer the time that has elapsed between the reporting period and the submittal of the amendment, the more problematic the process of validating the proposed chnages and the supporting documentation. In fact, such validation has been infeasible in some cases. Therefore, staff is proposing to add language to Rule 2002(b)(5) to provide clarity on which annual report submittals and/or revisions may be considered by staff in determining facility allocations.

Rules 2011 and 2012 - Delayed RATA Tests due to Extenuating Circumstances

Rules 2011 and 2012 set forth monitoring, reporting, and recordkeeping requirements for sources of SOx and NOx at RECLAIM facilities. The accompanying Appendices A to these rules outline in greater detail the technical specifications required for monitoring, reporting, and recordkeeping for RECLAIM sources such as the timing and frequency of Semi-Annual Assessments in the form of Relative Accuracy Test Audits (RATAs) for CEMS. RATAs must be conducted while the equipment is in operation. Equipment monitored by CEMS at some RECLAIM facilities, however, may experience extenuating circumstances that prevent them from conducting RATA tests in a timely manner.

Additionally, facilities under contract with the California Independent System Operator (CalISO), as well as electrical generating facilities owned and operated by municipalities, have experienced difficulties in meeting RATA deadlines because their equipment operates based on current energy demand and may not operate long enough (or at all) to conduct a RATA in the quarter in which the RATA is due. Electrical generating facilities with equipment under contract with CalISO or owned and operated by municipalities often do not know when demand for electricity will result in generation equipment being required to operate until a day prior, creating scheduling difficulties in conducting RATAs and precluding the use of non-operational status. The inherent inconsistent operational nature of such equipment at electric generating facilities sometimes causes a need to postpone their RATAs.

Under current rule requirements, facilities having such extenuating circumstances seek variances for indeterminate amounts of time. The proposed amendments would, under specific conditions and criteria, allow RECLAIM Facility Permit Holders of equipment experiencing these extenuating circumstances to postpone RATAs. The specific conditions and criteria are further explained in details in Appendix X.

Rules 2011 and 2012 - Typographical Edits

Staff also proposes to make several typographical clarifications and corrections in Rules 2011 and 2012 Appendix A, Attachment C B.2.b and Rule 2011 Appendix A, Attachment C B.2.e. Please see Appendix X for further explanations.

Draft Program Environmental Assessment (PEA)

A Notice of Preparation/Initial Study (NOP/IS) was released for a 57-day public review and comment period from December 5, 2014 to January 30, 2015. Eight comment letters were received from the public regarding the preliminary analysis in the NOP/IS. These comment letters and responses to individual comments are included in Appendix G of the Draft Program Environmental Assessment (PEA). In addition, on January 8, 2015, a CEQA and Socioeconomic Scoping Meeting was held. CEQA comments raised at the Scoping Meeting have been summarized and responded to in Appendix H of the Draft PEA. Socioeconomic comments raised at the Scoping Meeting and in the two comment letters specific to socioeconomic issues received are addressed in the Draft Socioeconomic Analysis.

Part I – BARCT Analyses for Refinery Sector

Part I contains the information related to the BARCT analyses for the refinery sector. Part I includes 10 Appendices from Appendix A to Appendix J that discuss 1) the NOx control technologies, 2) costs and cost effectiveness analyses for major NOx sources at the refineries, and 3) staff's review of the consultant's analyses. The NOx reductions co-benefits of the energy efficiency projects at the refineries are summarized in Appendix K. The Survey Questionnaires sent to the refineries in 2003 to collect pertinent information for this BARCT analyses are included in Appendix L.

Appendix A - Refinery Fluid Catalytic Cracking Units

Process Description

There are five refineries that operate six fluid catalytic cracking units (FCCU) in the SCAQMD: Chevron, ExxonMobil, Tesoro (Carson and Wilmington), Phillips66, and Valero. The FCCUs are classified as major sources of emissions in RECLAIM, and as such, the NOx emissions from FCCUs are required to be monitored with a continuous emission monitoring system (CEMS), and reported on a daily basis electronically to the SCAQMD. A brief description of the process is presented below.

An FCCU converts heavy oils into more valuable gasoline and lighter products. A schematic of the process is shown in Figure A.1. The process uses a very fine catalyst that behaves as a fluid when aerated with a vapor. The fluidized catalyst is circulated continuously between a reactor and a regenerator and acts as a vehicle to transfer heat from the regenerator to the oil feed in the reactor. The cracking reaction is endothermic and the regeneration reaction is exothermic. The fresh feed is preheated by heat exchangers to a temperature of 500-800 degrees Fahrenheit and enters the FCCU at the base of the feed riser where it is mixed with the hot regenerated catalyst. 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 degrees Fahrenheit. As the cracking reaction progresses, the catalyst surface is gradually coated with carbon (coke), reducing its efficiency. While the cracked hydrocarbon vapors are routed overhead to a distillation column for separation into lighter components, the oil remaining on the catalyst is removed by steam stripping before the spent catalyst is cycled to 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 degrees Fahrenheit. 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. The FCCUs in the SCAQMD are currently operated in a completely burn mode; what used to be the CO boilers are used as heat recovery devices without any supplemental fuel.

It is during the regeneration cycle that some of the catalyst is lost in the form of catalyst fines, and NOx, SOx and other pollutants are formed. The FCCU is a major source of sulfur oxides (SOx), nitrogen oxides (NOx), particulate matter (PM10, PM2.5), as well as ammonia (NH3), hydrogen cyanide (HCN) and other pollutants in the refinery. Approximately 90% of the NOx generated from the FCCUs are from the nitrogen in the feed that is accumulated in the coke which is then 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% 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 selective catalytic reduction (SCR), LoTOx scrubbers, and/or NOx reducing additives.

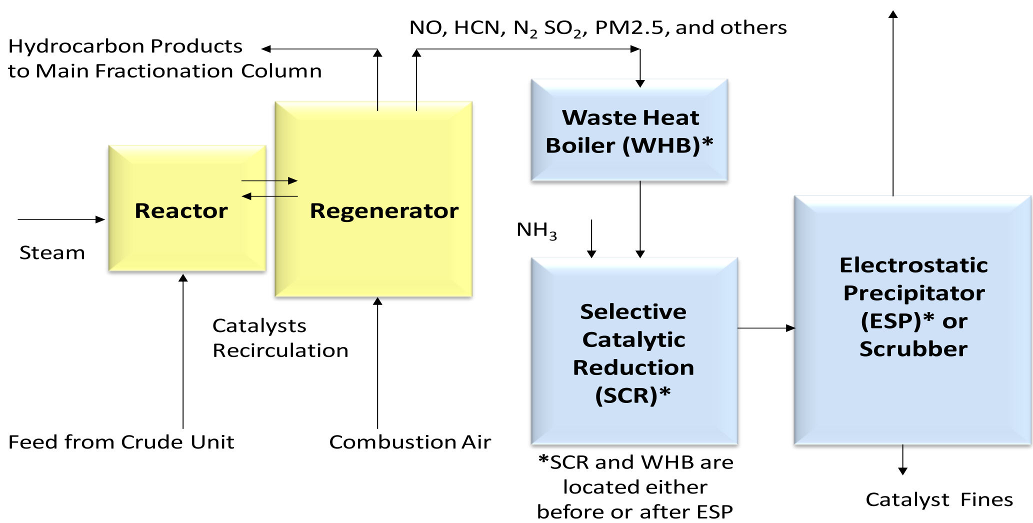


Figure A. 1 - Simplified Schematic of FCCU Process

Emission Inventory

As shown in Table A.1, the total 2011 NOx emissions from the six FCCUs (two with downstream CO boilers/heat exchangers) located in the SCAQMD are 1.08 tons per day.

Three FCCUs at Refinery 6, 1 and 5 use SCRs installed in 2000, 2003 and 2008, respectively to control NOx emissions. Three FCCUs at Refinery 4, 7 and 9 have no NOx controls.

As shown in Table A.1, Refinery 1's FCCU with SCR currently emits at a level under 2 ppmv NOx (with a 5 ppmv ammonia slip.) The NOx concentrations from other FCCU/CO units vary from 6 to 45 ppmv. Figure A.2 graphically shows the 2011 NOx emissions and the regenerator exhaust gas NOx concentrations for the six FCCUs in the SCAQMD. Comparing the data of the six FCCUs, Refinery 1's FCCU operating with SCR installed in 2003 has the lowest NOx emissions and the lowest NOx concentrations at below 2 ppmv.

As previously mentioned, 90% of the NOx emissions from the FCCUs are generated from the nitrogen in the FCCU feed (or coke in the regenerator.) Figure A.3 shows the NOx emissions compared to the FCCU feed rates. Comparing the data of the six FCCUs, Refinery 1 has the highest feed rate but achieves the lowest emissions with the use of an SCR.

Table A. 1 - 2011 Emissions for Refinery FCCUs

Facility ID	Device ID	Device	Process/NOx Control	2011 Emissions (lbs)	Current NOx ppmv @ 3% O2
5	203	REGEN1	FCCU/SCR	119,724	14.84
1	164	REGEN2	FCCU/SCR	16,686	1.21
6	151	REGEN3	FCCU/SCR	123,008	5.62
6	164	CO BOILER	FCCU/SCR	20,038	5.62
4	112	CO BOILER	FCCU/no control	157,150	21.0 - 27.6
4	96	REGEN4	FCCU/no control	in CO Boiler	21.00
7	1	REGEN5	FCCU/no control	101,648	12.88
9	36	REGEN6	FCCU/no control	249,277	35.5 - 45
			Total	**1.08 tons per day**	

Achieved-In-Practice Level for FCCU

Refinery 1 FCCU's SCR has demonstrated that a level of 2 ppmv NOx at 5 ppmv ammonia slip is achieved in practice. [Reference 1]

— The SCR was installed and operated since 2003. It was designed with a NOx inlet of 155 ppmv to achieve a level of 10 ppmv NOx outlet concentration (>90% control efficiency)

— At normal operations, the inlet NOx concentrations range from 40 - 80 ppmv, and the outlet NOx concentrations are typically below 2 ppmv with 5 ppmv ammonia slip (95% - 98% control efficiency). The SCR is capable of having three catalyst layers, each 29 ft x 29 ft x 4 ft deep; and is operated with two layers to reach 95% - 98% control. Catalyst life is 5 to 6 years.

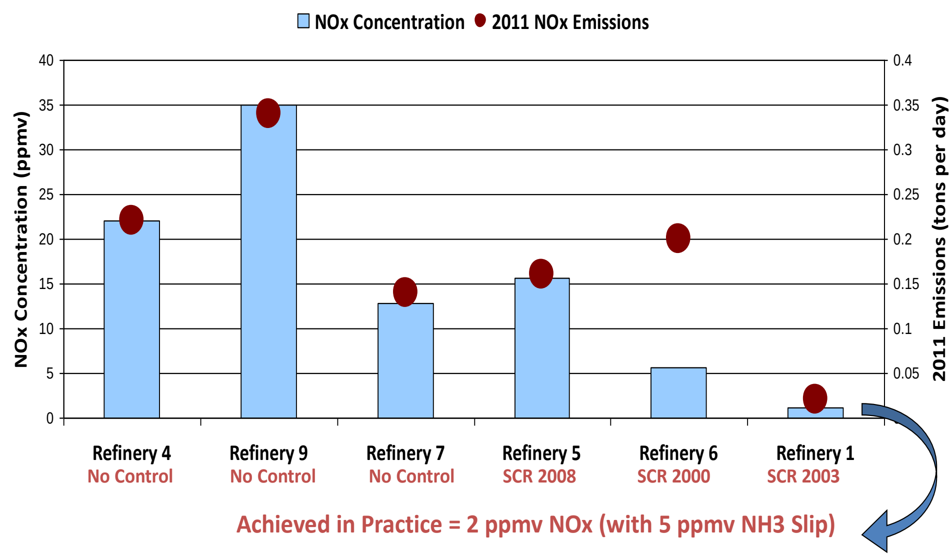


Figure A. 2 - 2011 NOx Emissions and NOx Concentrations for Refinery FCCUs

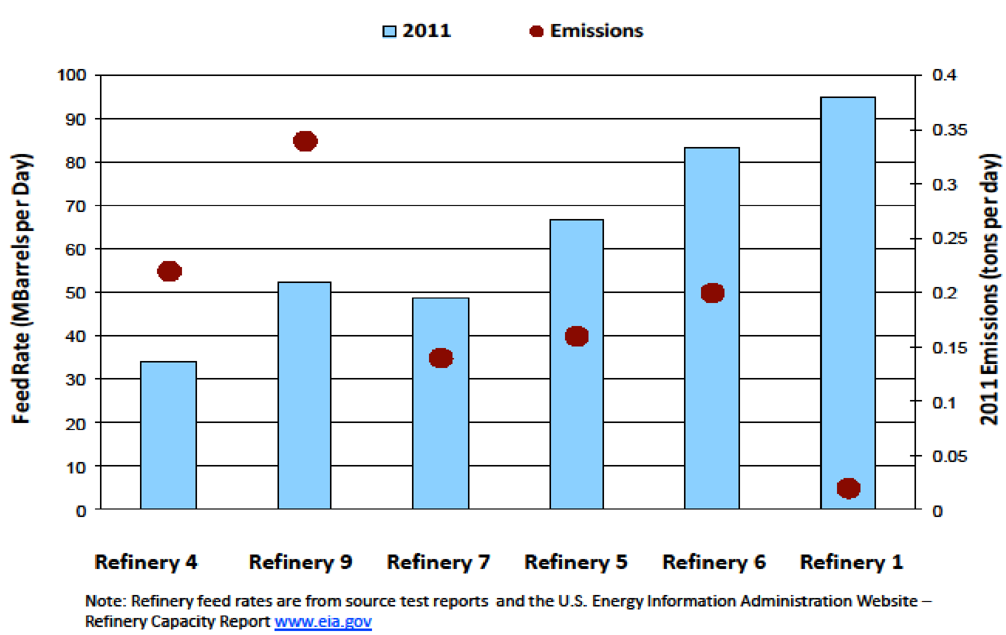


Figure A. 3 - 2011 NOx Emissions and Feed Rates for Refinery FCCUs

Control Technology

The commercially available control technologies for NOx are discussed below.

Selective Catalytic Reduction (SCR)

For the past two decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available. SCRs can be designed to reduce 95%-98% NOx emissions from the FCCUs and achieve 2 ppmv NOx while maintaining a low ammonia slip of less than 5 ppmv. [1-17]

Selective catalytic reduction (SCR) is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen through the following reactions: [2 - 4]

$4\ NH_3 + 4\ NO \rightarrow 4\ N_2 + 6\ H_2O$ (Reaction 1)

$4\ NH_3 + 2\ NO + 2\ NO_2 \rightarrow 4\ N_2 + 6\ H_2O$ (Reaction 2)

It should be noted that, at temperatures above 797 ^oF, ammonia can be oxidized to form NO and N_2O. These are undesirable reactions since NO and N_2O will ultimately convert to NOx and increase the NOx emissions. [5]

$4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O$ (Reaction 3)

$4\ NH_3 + 4\ NO + 3\ O_2 \rightarrow 4\ N_2O + 6\ H_2O$ (Reaction 4)

A successful SCR catalyst can facilitate the reduction of NH_3 (Reaction 1 and 2) while subsiding the NH_3 oxidation reactions (Reaction 3 and 4). Typically, the SCR catalysts are vanadium, titanium, and/or zeolite based with different sizes and shapes, and have various ranges of operating temperatures: [5 – 8, 18]

Conventional SCR catalysts:	400 degrees F - 800 degrees F
Low temperature SCR catalysts:	300 degrees F - 400 degrees F
High temperature SCR catalysts:	800 degrees F - 1100 degrees F

The stochiometric amount of ammonia required is 1 mole of NH_3 per mole of NOx reduced (NH_3/NOx = 1). Ammonia injection and mixing are critical since a non-uniform distribution and mixing of ammonia can result in inadequate NOx conversion and extensive ammonia slip.

To reduce the ammonia slip caused by imperfect ammonia distribution and mixing, SCR manufacturers have developed the Ammonia Slip Catalyst (ASC), a layer of catalyst which can be installed downstream of the SCR catalyst. Early generation of ASCs were based on precious metal which is highly active for NH_3 oxidation. The current newly developed ASCs selectively favor the NH_3 reduction over the NH_3 oxidation: NH_3 is partially oxidized to NO (Reaction 3) and NO is then quickly reduced to N_2 (Reaction 1 and 2). In addition, the advanced ACSs highly support the oxidation of CO to CO_2. Other advantages of ASCs are summarized below: [5, 9-10]

— Enhancing the selective reduction of NO to N2 and supporting the oxidation of CO to CO2 while suppressing the oxidation of NH3 to NOx;
— Allowing for operations at higher NH_3/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.

In the SCAQMD, aqueous ammonia is required to be used with SCRs instead of anhydrous ammonia due to safety reasons. In general, aqueous ammonia has lower risks and higher operating costs than anhydrous ammonia. A larger volume of aqueous ammonia will be required to achieve the same NOx reduction, thus increasing the costs of deliveries (e.g. for 29% aqueous ammonia, the delivery costs is in transporting 71% water with the ammonia.) Aqueous ammonia 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. [11-13]

Sulfur dioxide (SO_2) to sulfur trioxide (SO_3) conversion and ammonium bisulfate (ABS) formation are undesirable reactions in the SCR process. SO_3 and ABS can cause plugging at downstream components. However, the main factors affecting the formation of ABS, such as temperature, the amount of ammonia slip, molar ratio of ammonia to NOx, the SO_3 concentrations, and fly ash contents; and the methods to control SO_3 ABS formation to reduce its negative effects have been well investigated, documented, and implemented by the SCR manufacturers as well as the SCR users. In addition, ABS is unlikely to be a problem for low flue gas sulfur units. [14]

LoTOx™ Application with Scrubber

LoTOx™ stands for "Low Temperature Oxidation" process in which ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds. These soluble compounds can then be removed by absorption in caustic solution, lime or limestone. The LoTOx™ process is a low temperature operating system, optimally operating in a range of 140 - 325 degrees F. The LoTOx™ is a registered trademark of Linde LLC. (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. The LoTOx application is explained below. [19 - 27]

A typical combustion process produces about 95% NO and 5% NO_2. Both NO and NO_2 are relatively insoluble in aqueous solution, and thus a wet gas scrubber is not efficient in removing these insoluble compounds from the flue gas stream. However, with the introduction of ozone, NO and NO_2 can be easily oxidized to highly soluble compounds N_2O_5 (Reaction 5 and 6) and subsequently converted to nitric acid HNO_3 (Reaction 7). The nitric acid is then rapidly absorbed in caustic solution (Reaction 8), limestone or lime (Reaction 9 and 10), and removed from the wet scrubbers. In addition, the rates of oxidizing reactions for NOx (Reaction 5 and 6) are fast compared to SO_2 oxidation reaction (Reaction 11), and as a result, there is no ABS or SO_3 formation. The LoTOx process can be integrated with any types of wet scrubbers (e.g. venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs).

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 - Fast)
$2\ NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2\ HNO_3$	(Reaction 7)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO3 + CaCO3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO3 + Ca(OH) \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 - Very slow)

The LoTOx process requires oxygen supply and ozone generation. Oxygen is used to generate ozone on site. Typically oxygen is stored as liquid in vacuum jacketed vessels or is delivered by pipeline. Ozone is an unstable gas and it is typically generated on demand using an ozone generator. An ozone generator is shaped similar to a shell and tube heat exchanger. A corona discharge is used to dissociate oxygen into individual atoms; and the oxygen atoms combine with other oxygen molecules to form ozone. An ozone injection manifold should be designed to achieve uniform distribution and complete mixing. A ratio of NOx/O_3 of about 1.75 – 2.5 is needed to achieve 90% to 95% NOx conversion and reduction. Since sulfites are ozone scavengers, the LoTOx process typically has a very low ozone slip of 0-3 ppmv.

Several advantages of LoTOx application in comparison to SCR are:

- LoTOx is a low temperature operating system, meaning that it does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases.

- LoTOx can be an 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 ABS issues associated with LoTOx application.

BOC Gases received a grant funded partially by the California Air Resources Board to demonstrate the LoTOx technology at a reverbertory furnace used for lead smelting, operated by Quemetco Inc., City of Industry in California. The demonstration was successful, accomplishing > 90 percent NOx removal which led to a full scale system installation in 2001.[23] Today, there are more than

50 applications engineered by Linde since 1997,[19] and more than two dozen applications with EDV™ scrubbers engineered by BELCO since 2007.[26] EDV™ is a registered trademark of BELCO. LoTOx with EDV™ scrubber is shown in Figure A.4.

Table A.2 contains a list of the LoTOx applications for FCCUs, boilers, furnaces, and other combustion equipment. This is not an inclusive list. Applications in gas-fired and high sulfur coal-fired units met 95% control (2 ppmv - 5 ppmv). Current installations in refineries have achieved NOx level of 8 ppmv -10 ppmv (85% - 95% control efficiency). Manufacturers have confirmed that LoTOx can be designed to achieve 2 ppmv NOx from current inlet concentrations (85%-95% control efficiency) for FCCUs.

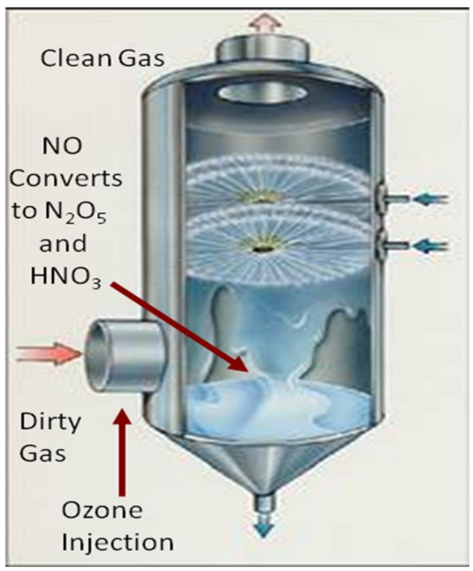


Figure A. 4 - EDV Scrubber with LoTOx Application

Table A. 2 – List of LoTOx Applications

No	Application	Exhaust Gas Flow (scfm)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1	400 HP natural gas fired boiler *	4,000	30-70	2	97%	1997-98
2	Stainless steel pickling	4,000	3400	100	97%	2000
3	25 MW coal fired boilers	90,000	200	10-20	95%	2001
4	Lead recovery furnace	26,000	50-150	10	93%	2002
5	1000 HP natural gas fired boiler *	10,000	20-40	4	90%	2001
6-10	Five (5) FCCUs in the U.S.	40,000-260,000	70-120	8-20	80%	2007

11-12	Sulfuric acid plants in the U.S.	2 x 16,800	90	10	90%	2008
13-23	Nine (9) FCCUs and 2 LoTOx ready installations in the U.S.	12,000 – 310,000	30-250	10-18.5	93%	2008-15
24-40	Ten (10) FCCUs, a refinery boiler, 6 LoTOx ready installations in China	90,000-390,000	100-350	20-73	80%	2012-15
41-42	FCCUs in Thailand & Romania	43,000-135,000	230-250	20-73	80%	2015-19

Note: See Reference 19. * Units are in Southern California.

No	Application	Capacity (bpsd)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1	FCCU, Arkansas	20,000	70-100	10	86%	2007
2	FCCU, Texas City, TX	130,000	100-200	10	95%	2007
3	FCCU, Texas City, TX, retrofit	60,000	100-150	8	95%	2007
4	FCCU, Texas City, TX, retrofit	52,000	70-100	10	90%	2007
5	FCCU, Houston, TX, retrofit	58,000	100-150	10	93%	2007
7	FCCU, St. Charles, LA, retrofit	100,000	Confidential			2010
8	FCCU, Corpus Christi, TX, retrofit	45,000				2010
9	FCCU, Delaware, DE, retrofit	75,000				TBD
10	FCCU, El Dorado, KS	40,000	150	20	86%	TBD
11	FCCU, Ardmore, Oklahoma	40,000	TBD			TBD
12	FCCU, Three Rivers, Texas	28,000				TBD
13	FCCU, Placid Refining, LA	30,000				TBD

Note: Refer to Reference 20 for additional installations inside and outside of the U.S. Some scrubbers have built in ready for LoTOx retrofit but ozone generators have not yet been installed as of May 2013.

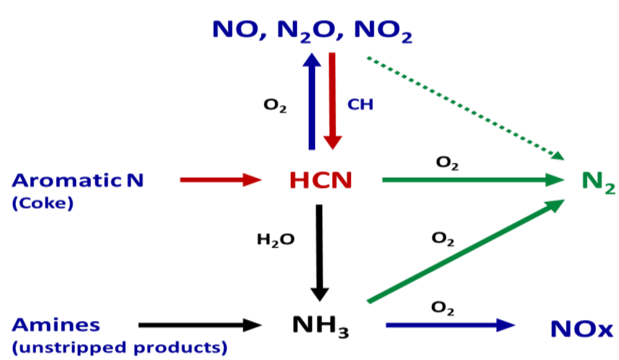
NOx Reduction Additives

The combustion in the FCCU regenerator generates a dozen of various pollutants (NO, N_2O, NO_2, HCN, NH_3, CO, SO_2 etc) and the dynamic interaction of these compounds with each other is complex. A simplified version of the chemical reactions in the FCCU regenerator is shown in Figure A.5. "Fuel" nitrogen in the coke is first converted to HCN. HCN is thermodynamically unstable and it is converted to NH_3, N_2, NO, N2O, NO_2 compounds. The rates of these reactions depend heavily on the regenerator temperatures and the regenerator configuration. NOx reduction additives can be used to promote the conversion of NOx, HCN, and NH_3 to N_2 and reduce NOx emissions. The removal efficiency for NOx Reduction Additives is reported to vary from 50% to 80%. [28-38]

Manufacturers of the NOx reduction additives such as BASF, INTERCAT and Grace Davidson recommended the following best practices to minimize the NOx formation with the use of their additives, and at the same time, promote the conversion of CO to CO2:

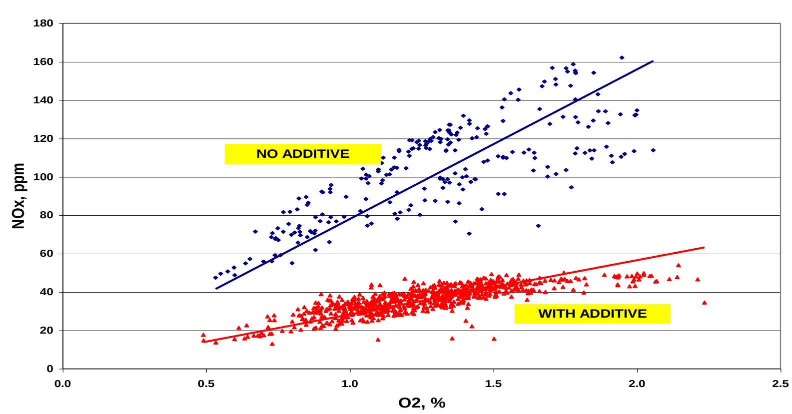
— Minimizing excess oxygen,
— Reducing feed nitrogen, and
— Utilizing non-platinum CO promoters

Figure A.6 shows outlet NOx concentrations of a FCCU with and without the use of NOx Reduction Additives. Data in Figure A.6 shows that higher excess oxygen favors the formation of NOx rather than N_2, and NOx Reducing Additives are capable of removing 60% of NOx emissions. NOx Reduction Additives cannot yet reduce NOx to 2 ppmv levels, however additives may be used in combination with other control technologies to reach the targeted levels. Two manufacturers indicated that NOx additives generally would cost about $15-$20 per pound and would be used at a rate between 1-3% of the FCC fresh catalyst addition rate. The NOx control effectiveness of the NOx Reducing Additives would be very specific for each FCCU application.



(Picture taken from References 22 and 23)

Figure A. 5 - Nitrogen Chemistry in the FCC Regenerator



(Picture taken from Reference 22)

Figure A. 6 - NOx Reduction Additive Reduces NOx Emissions by 60%

Costs and Cost Effectiveness for SCRs

Refinery 5, 6 and 7

Costs for the SCRs at Refineries 5, 6 and 7 were derived based on Refinery 1's data. Refinery 1 SCR achieved 2 ppmv NOx and 5 ppmv NH_3 slip. Refinery 1 provided staff with the total installed costs, ammonia costs, and catalysts replacement costs for their SCR. [1] Staff estimated Present Worth Value (PWV) for Refinery 1 SCR using the equations below assuming 4% interest rate and 25-years SCR life. The PWV of Refinery 1 SCR was estimated to be $41 million dollars as shown in Table A.3.

$$PWV_{Ref\ 1} = TIC_{Ref\ 1} + (15.62 \times AC_{Ref\ 1}) + (2.52 \times CR_{Ref\ 1}) \qquad \text{(Equation 1)}$$

Where:

$PWV_{Ref\ 1}$ = Present Worth Value, $
$TIC_{Ref\ 1}$ = Total Installed Costs, $
$AC_{Ref\ 1}$ = Annual Operating Costs, $
$CR_{Ref\ 1}$ = Catalysts Replacement Costs, $

The PWV of Refinery 5, 6, and 7 SCRs were estimated using the PWV of Refinery 1 SCR and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power as follows. The PWVs of SCRs for Refinery 5, 6 and 7 were estimated to be $33 million, $57 million and $27 million respectively as shown in Table A.3.

$$PWV_{Ref\ 5} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 5} / \text{Flow Rate}_{Ref\ 1})^{0.7} \qquad \text{(Equation 2)}$$
$$PWV_{Ref\ 6} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 6} / \text{Flow Rate}_{Ref\ 1})^{0.7}$$
$$PWV_{Ref\ 7} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 7} / \text{Flow Rate}_{Ref\ 1})^{0.7}$$

Refineries 5 and 6 installed their SCRs in 2008 and 2000 respectively. In order to meet the 2 ppmv NOx proposed level, they may choose to 1) retrofit their existing SCRs, or 2) add additional catalysts to their existing SCRs if space is available (Note: Refinery 1 only utilizes 2 layers out of 3 layers of catalysts to meet 95% - 98% control), or 3) change the existing catalysts to a more effective catalyst type. As shown in Table A.3, the PWVs in these scenarios can be potentially less than $33 million and $57 million dollars for Refineries 5 and 6, respectively.

Refinery 4 and 9

Refinery 4 and Refinery 9 FCCUs have no controls for NOx emissions. Several manufacturers provided costs information for the SCRs at Refinery 4 and Refinery 9 to achieve 2 ppmv and 5 ppmv NOx.[15 - 17] One manufacturer indicated that the flue gas exist temperatures at the two refineries must be raised to 650 degrees F to avoid SO_2/SO_3 and ABS related problems; and estimated that this would add about 10% to the overall costs of the equipment.

The EPA's OAQPS Guidelines' approach was used to estimate the following costs: [4]

Instrumental = 10% x Equipment Cost
Sales Tax = 9% x Equipment Cost
Freight = 5% x Equipment Cost
Thus, Total Equipment Cost = 1.24 x Equipment Cost = 1.24 EC
Installed Costs = 50% of Total Equipment Costs

Total Installed Costs (TIC) = (1.24 EC) + 0.5(1.24 EC) = 1.86 EC (Equation 3)

Based on its reported data, the annual operating costs of Refinery 1's SCR during its 25-years life is about 20% of the total installed costs. Staff used this 20% factor to estimate the 25-year operating costs for the new SCRs at all the refineries. Staff added a contingency factor of 1.5 to cover additional uncertainties for both the TIC and the annual operating costs.

$PWV_{\text{Ref 4, Ref 9}}$ = 1.5 [(1.86 EC) + 0.2 (1.86 EC)] = 3.35 EC (Equation 4)

Therefore, the PWVs would become $16 million and $19 million for Refinery 4 and 9 as shown in Table A.3 using the EPA OAQPS Guidelines' approach. In lieu of using a factor of (1.86 x 1.5 = 2.79) to estimate the TICs and PWVs, the refineries and consultants used a factor of 4.5, and if a factor of 4.5 was used, the PWVs would be $23 million and $31 million for Refinery 4 and 9 as shown in Table A.5 below.

Cost effectiveness (CE) was estimated as follows and is summarized in Table A.3:

CE = PWV / (ER x 365 days x 25 years) (Equation 5)

Where:

CE = Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Emission Reductions, tpd

The cost effectiveness in Table A.3 is estimated using DCF method. The cost effectiveness calculated based on the LCF method is about 1.65 times higher than the cost effectiveness estimated by the DCF method (e.g. $18K per ton DCF compared to $30K per ton LCF.)

Table A. 3 - Costs and Cost Effectiveness for SCRs (December 2014)

Fac ID	Emissions (tpd)	NOx (ppmv)	% Control	Emission Reduction (tpd)	PWV ($M)	CE ($/ton)
1	0.02	<2	95%	-	(41)	(10,181)
5	0.16	15	87%	0.14	< 33	< 25,259
6	0.20	6	64%	0.13	< 57	< 49,408
7	0.14	13	84%	0.12	27	25,455
4	0.22	21-23	91%	0.20	16	8,961
9	0.34	34-52	95%	0.32	19	6,537
Total for Ref 4,9,5,6 and 7				**0.91**	**152**	**Avg <18,422**

Consultant's Analysis for SCRs and Staff's Revised Estimates for SCRs

In 2014, staff contracted Norton Engineering Consultants (NEC) to conduct a BARCT analysis for the refinery sector. [39] Table A.4 shows a comparison between NEC's and staff's estimates:

Table A. 4 – Comparison of SCR Costs Estimated by Staff and NEC (December 2014)

Fac ID	SCAQMD's Estimates (note 1) ($M)	NEC's Estimates ($M)
5	<33	<46 (note 2)
6	<57	<46 (note 2)
7	27	42 (note 3)
4	16	38
9	19	39
Total	**152**	**211**

Note: 1) SCAQMD's estimates were presented at the Jan 22, 2014 WGM. 2) Over-estimated because the SCR already has been installed. 3) This FCCU will be dismantled

NEC recommended SCRs with 3 layers of catalysts and 2 layers of markup factors. [5] After extensive discussion, staff used a different approach than NEC to estimate the SCR costs because 1) Refinery 1 achieved 2 ppmv NOx with only 2 layers of catalysts and 2) the estimated costs of SCRs extrapolated from Refinery 1's SCR for Refinery 4 and 9's SCRs would be about $22 M and $29 M, smaller than NEC's estimates of $38 M and $39 M, which indicate that the NEC's estimates were high. See Appendix F for further details.

NEC indicated that the EPA factors in the EPA OAQPS Guidelines (Equation 3) were not sufficient to cover retrofitting applications at the refineries. The refineries also indicated the factors should be about 4. To reconcile this difference, staff presents the PWVs as a range of costs

[5] NEC first marked-up the costs provided by the manufacturer by 35%. NEC named this markup as "bid conditioning factor" to cover the "low" bid provided by the manufacturer. NEC then added 75% increase in labor costs to the costs provided by the manufacturer. NEC did not provide any references to their markup factors and simply stated that the factors were based on their own experience.

from $152 million to $163 million using data in 1) Table A.3 above (costs estimated with EPA factors), 2) Table F.2 of Appendix F (costs extrapolated from actual costs of Refiner 1's SCR) and 3) Table F.5 of Appendix F (costs estimated with 2 layers of markups used by NEC, which is equivalent to a factor of about 4.5.).

Table A.5 summarizes the costs estimated by the three approaches mentioned above.

- $152 M was calculated based on 1) prorating Refinery 1's data to estimate the costs for Refinery 5, 6 and 7; and 2) using manufacturers data and the methodology described in the EPA OAQPS Guidelines to estimate the costs for Refinery 4 and 9. See Table A.3.

- $154 M was calculated based on prorating Refinery 1's data to estimate the costs for all 5 refineries. See Table F.2 of Appendix F.

- $163 M was calculated using cost data provided by the manufacturers with 2 layers of marked up factors that resulted in a multiplication factor of 4.5 for TIC instead of the 1.86 derived from the EPA OAQPS Guideines and a 1.5 contingency factor (e.g. $29 M x 4.5 / 1.86 / 1.5 = $31 M). Note that Ref 4's FCCU is scheduled to be shutdown in the near future which would result in lowering the costs estimated for the FCCU category. See Table F.5 of Appendix F.

Table A. 5 – Revised Costs and Cost Effectiveness for SCRs (March 2015)

Fac ID	Emission Red (tpd)	Table A-3 PWV ($M)	Table F-2 PWV ($M)	Table F-5 PWV ($M)	Range of PWV ($M)	CE ($/ton)
5	0.14	<33	<34	<36	<33 – 36	<25K - $27K
6	0.13	<57	<40	<42	<57 – 42	<49K – 36K
7	0.12	27	29	31	27 – 31	25K – 29K
4	0.20	16	22	23	16 – 23	9K – 13K
9	0.32	19	29	31	19 – 31	7K – 11K
Total	**0.91**	**152**	**154**	**163**	**152 - 163**	**18K – 20K**

Costs and Cost Effectiveness for NOx Reduction Additives

NOx reduction additives can reduce about 10% - 70% NOx emissions depending on the FCCU regenerator configuration and operating condition. The use of NOx reducing additives may not achieve the ultimate goal of 2 ppmv, but may help the refineries achieve the future facility overall shave. Cost effectiveness for NOx reducing additives were estimated to be about $6,460 per ton of NOx reduced using DCF method ($10,660 per ton using LCF method.) The inputs and results were summarized in Table A.6.[38]

Table A. 6 - Costs and Cost Effectiveness for NOx Reduction Additives

Inputs	
Baseline NOx	40 ppmv
NOx reduction	50%
Cost of NOx Reduction Additives	$15 per lb
NOx Reduction Additives	1.5% of total catalysts
Catalyst Addition Rate	4 ton per day
FCCU Rate	70 million barrels per day
Results	
NOx Reduction Additives Costs	1800 $/day
NOx Reduction	348 lbs/day
Cost Effectiveness for NOx Reducing Additives	**6,460 $/ton**

Costs and Cost Effectiveness for LoTOx Scrubbers

The FCCUs at Refinery 4 and Refinery 9 currently have no control. Refinery 7's FCCU has a scrubber. Process data for these three refineries' FCCUs were provided to a manufacturer, and the manufacturer provided estimates for the total installed costs and annual operating costs. [27]

The total installed costs provided by the manufacturer included the ozone generator, the associated closed loop chiller, and cooling pump, the ozone injection lances, associated platforms and access steel, some interconnecting piping and supports, valves and instruments and freight to the job site. The manufacturer did not include oxygen storage and vaporization which was only necessary if the refinery did not yet have oxygen at the site for other uses, electrical equipment and foundation. Staff added a contingency factor of 2 to markup the costs provided by the manufacturer to account for any additional modifications needed at the site and any variations in annual operating costs such as electricity or oxygen.

The PWV for Refineries 4, 7 and 9 LoTOx applications were estimated as follows:

$$PWV_{\text{Ref 4, 7 and 9}} = \text{Contingency Factor} \times (TIC_{\text{Ref 4, 7 and 9}} + (15.62 \times AC_{\text{Ref 4, 7 and 9}}))$$

Where:

$PWV_{\text{Ref 4, 7 and 9}}$ = Present Worth Value $
$TIC_{\text{Ref 4, 7 and 9}}$ = Total Installed Costs provided by vendor, $
$AC_{\text{Ref 4, 7 and 9}}$ = Annual Operating Costs provided by vendor, $
Contingency Factor = 2

Refineries 5 and 6 currently employ SCRs to reduce their FCCU's NOx emissions. Scrubbers may be needed to reduce the SOx emissions from their FCCUs, and LoTOx can be installed concurrently with the scrubbers to further reduce NOx emissions. The PWV for LoTOx applications at Refineries 5 and 6 were estimated based on the PWV for LoTOx applications at Refineries 4 and 7 and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power as follows:

$$PWV_{Ref\ 5} = PWV_{Ref\ 5} \times (Flow\ Rate_{Ref\ 5} / Flow\ Rate_{Ref\ 4})^{\wedge 0.7}$$
$$PWV_{Ref\ 6} = PWV_{Ref\ 7} \times (Flow\ Rate_{Ref\ 6} / Flow\ Rate_{Ref\ 7})^{\wedge 0.7}$$

The present worth values and cost effectiveness values are summarized in Table A.7 based on information available as of December 2014. The average cost effectiveness is $15 K per ton using DCF method and $25 K per ton using LCF method.

The manufacturer estimated that a plot space for the ozone generator and accessories to be about 25 ft x 35 ft. The first LoTOx application was put in service in 1997, and at that time, it typically had a large foot print (e.g. 1st generation LoTOx application at a Texas refinery required a foot print of 30 ft x 80 ft.) The newer generation LoTOx application has a much smaller footprint (e.g. an equivalent unit to the Texas refinery application now requires only 25 ft x 30 ft).

Table A. 7 - Costs and Cost Effectiveness for LoTOx Applications (December 2014)

Fac ID	Emissions (tpd)	NOx (ppmv)	% Control	Emission Reduction (tpd)	PWV ($M)	CE ($/ton)
4	0.22	21-23	91%	0.20	19	10,767
7	0.14	13	84%	0.12	16	15,199
9	0.34	34-52	95%	0.32	32	10,631
5	0.16	15	87%	0.14	24	18,590
6	0.20	6	64%	0.13	34	29,502
Total for Ref 4,9,5,6 and 7				**0.91**	**125**	**Avg <15,124**

Staff did not include the costs for scrubbers and waste water treatment in Table A.7. Since Refinery 5 and 6 already have SCRs, they will likely to use their SCRs to control NOx. For Refinery 4, 7 and 9, staff included the costs for scrubbers with waste treatment as calculated in the 2010 SOx RECLAIM projects to the costs of the LoTOx application shown in Table A.6. Staff also estimated the overall cost effectiveness for the LoTOx/scrubbing multi-component air pollution control as shown in Table A.8.

Table A. 8 – Revised Costs and Cost Effectiveness for LoTOx Scrubbers (March 2015)

Fac ID	NOx Emission Reductions (tpd)	SOx Emission Reductions (tpd)	PWV for LoTOx ($M)	PWV for Scrubbers ($M)	Total PWV ($M)	CE (K$/ton)
4	0.20	0.20	19	91	110	30
7	0.12	0.87	16	51	67	7
9	0.32	0.58	32	90	121	15

Note: 1) SOx emission reductions were taken from Table 3-11, Chapter 3, SOx RECLAIM Staff Report, dated November 2, 2010. [40] 2) PWVs for scrubbers including waste treatment were based on information provided on Table 3-12, Chapter 3, SOx RECLAIM Staff Report, dated November 2, 2010, and a Marshall Swift Index of 1.1. [40] 3) It is assumed that retrofitting existing scrubber for Refinery 7 would cost about half of the costs estimated for the installation of the new scrubber under SOx RECLAIM project.

Incremental Costs and Cost Effectiveness

The BARCT level for the FCCUs in 2005 was set at 85% reduction. The costs for SCRs to meet 85% reductions were estimated to be $111.1 million. The estimated emission reductions were 0.48 tons per day. A Marshall index of 1.25 was used to raise the costs of $111.1 million dollars to current dollars of $138.88 million.

Staff estimated the overall PWVs for 2 cases as shown in Table A.9:

Case 1: Assuming that all 5 refineries will use SCRs to achieve the proposed BARCT level of 2 ppmv. Using the low end costs for SCRs in Table A-5, the total PWVs to achieve 2 ppmv NOx level would be $152 million.

Case 2: Assuming Refinery 5 and 6 will use SCRs (using the high end costs for SCRs in Table A.5) and Refinery 4, 7 and 9 will use LoTOx and scrubbers (Table A-8) for multi-component control. The total PWVs would be $375 million.

Incremental cost effectiveness to achieve a more stringent of 2 ppmv NOx from a less stringent level of 85% control during 25-years life of the control device is estimated as follows and shown in Table A.10:

$$CE_{\text{incremental}} = (PWV_{2\text{ ppmv}} – PWV_{85\%\text{ control}}) / ((ER_{2\text{ ppmv}} – ER_{85\%\text{ control}}) \times 25 \text{ yrs} \times 365 \text{ days})$$

Where:

$CE_{\text{incremental}}$ = Incremental Cost Effectiveness, $/ton
$PWV_{2\text{ ppmv}}$ = Sum of all SCR (or LoTOx) costs to meet 2 ppmv, $
$PWV_{85\%\text{ control}}$ = Sum of all SCR costs to meet 85% reduction, $ = $139 M
$ER_{2\text{ ppmv}}$ = Total emission reductions achieved at 2 ppmv NOx, tpd

= 0.91 tpd estimated from 2011 baseline

$ER_{85\% \text{ control}}$ = Total emission reductions achieved with 85% control, tpd

= 1.08 tpd – 0.60 tpd = 0.48 tpd

Table A. 9 – Present Worth Values of SCRs and LoTOx/Scrubbers for FCCUs (March 2015)

Fac ID	Case 1 - PWV ($M)	Case 2 - PWV ($M)
5	<33 (SCR)	<36 (SCR)
6	<57 (SCR)	<57 (SCR)
7	27 (SCR)	67(LoTOx and Scrubber)
4	16 (SCR)	110(LoTOx and Scrubber)
9	19 (SCR)	121(LoTOx and Scrubber)
Total	**152 (all SCRs)**	**391 (SCRs and LoTOx/Scrubbers)**

Table A. 10 – Incremental Cost Effectiveness of SCRs and LoTOx Scrubbers for FCCUs (March 2015)

	Emission Reductions (tpd)	PWV ($M)
SCR for 85% control	0.48 tpd NOx	139
SCR for 2 ppmv for all 5 Refineries	0.91 tpd NOx	152
SCR for 2 ppmv for Ref 5, 6 and LoTOx/Scrubber for Ref 4,7, 9	0.91 tpd NOx and 1.65 tpd SOx	391
Case 1 – Incremental Cost Effectiveness: SCR – SCR for all 5 Refineries (152 - 139) / (0.91 – 0.48) / 25 / 365 = 3,444 $/ton DCF and 5,683 $/ton LCF		
Case 2 – Incremental Cost Effectiveness: SCR – SCR for Ref 5, 6, and SCR - LoTOx for Ref 4, 7, 9 (391 – 139) / (0.91 + 1.65 – 0.48) / 25 / 365 = 13K $/ton DCF and 23K $/ton LCF		

Staff's Recommendation

Staff proposes a BARCT level of 2 ppmv NOx for FCCUs because 1) Refinery 1 FCCU's SCR already achieved 2 ppmv NOx at 5 ppmv NH3 slip; and 2) NOx control technologies such as SCR, LoTOx, and NOx Reduction Additives are commercially available and can be used in connection with each other to achieve 2 ppmv NOx in a cost-effective manner.

Cost information submitted by SCR and LoTOx manufacturers were used to develop the cost analysis, which provide sufficient evidence that a level of 2 ppmv NOx is feasible and cost-effective for FCCUs in the SCAQMD. It should also be noted that NOx reducing additives, which can reduce 50% or more of NOx emissions, can be used in parallel with SCRs and LoTOx applications if needed to meet the proposed BARCT level of 2 ppmv NOx.

In summary:

<u>Case 1:</u>

Total PWVs = $152 M with SCRs for all 5 refineries
Total incremental costs = $13 M
Incremental emission reductions = 0.43 tpd NOx
Incremental cost effectiveness with SCRs = 3,444 $/ton DCF or 5,700 $/ton LCF

<u>Case 2:</u>

Total PWVs = $375 M with SCRs for Ref 5 and 6 and LoTOx/scrubbers for Ref 4, 7 and 9
Total incremental costs = $236 M
Incremental emission reductions = 0.43 tpd NOx and 1.65 tpd SOx for 5 FCCUs
Incremental cost effectiveness = 12,432 $/ton DCF or 20,516 $/ton LCF

References for FCCUs

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Appendix B – Refinery Boilers and Process Heaters

Process Description

Boilers and process heaters are used extensively in almost all of the processes in refinery such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. Figure B.1 provides a simplified diagram of the processes where boilers and heaters are used. There are about 23 boilers and 189 heaters in the refineries classified as major or large NOx sources. The refinery heaters and boilers primarily burn refinery gas which is generated at the refinery. Most of these boilers and heaters use natural gas as back-up or supplemental fuel. Liquid fuel or solid fuel is rarely used in refinery boilers and heaters. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx and "prompt" NOx.

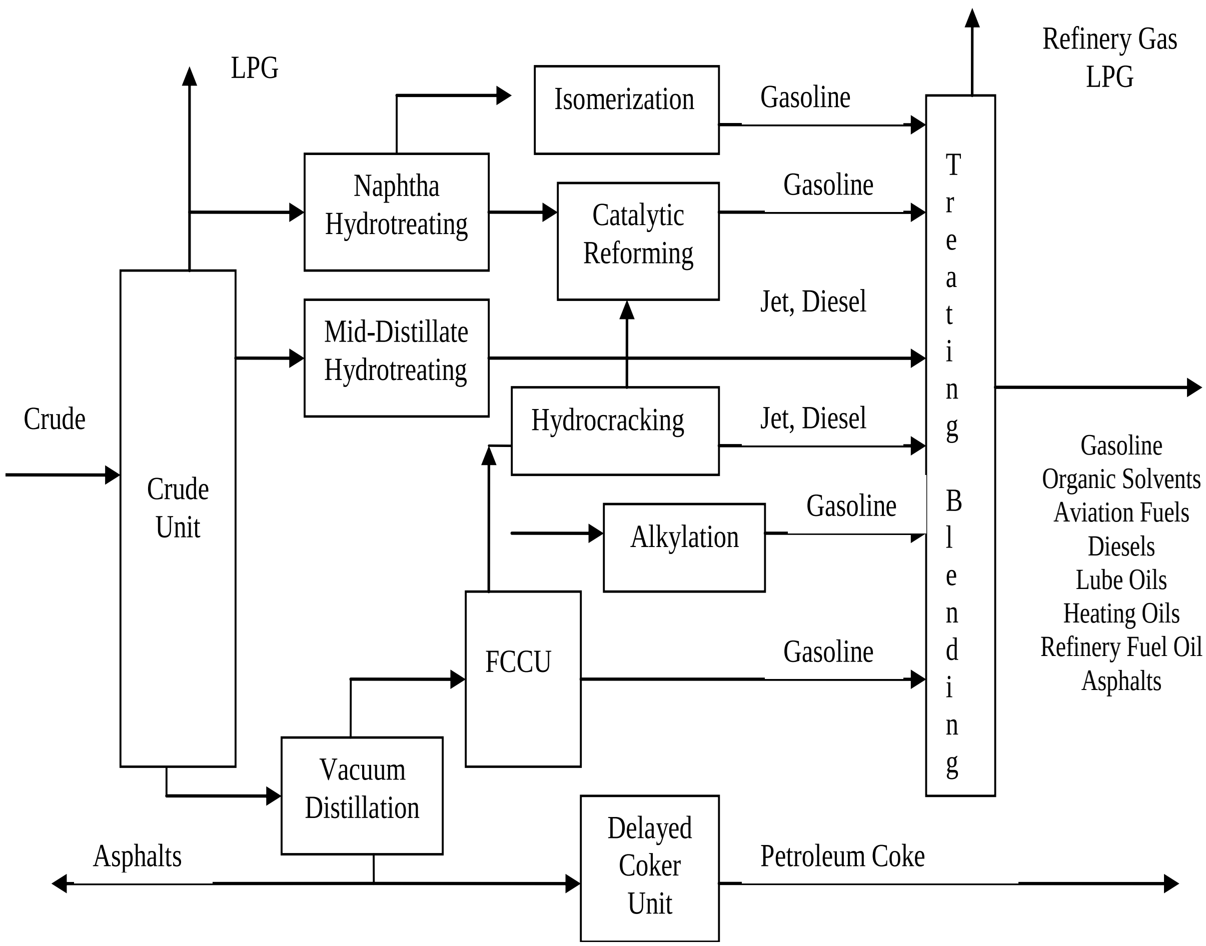


Figure B. 1 - Refinery Processes

Emission Inventory

There are a total of 212 boilers and heaters classified as major and large NOx sources at the refineries. The distribution of boilers and heaters and their emissions are shown in Table B.1. Collectively, the 212 boilers and heaters emitted about 7.39 tons per day in 2011. Their NOx concentrations at the stack vary from 1.6 ppmv for units equipped with Selective Catalytic Reduction (SCR) to 120 ppmv for units with no control.

It should be noted that in 2005, the SCAQMD set BARCT levels from 5 ppmv – 12 ppmv for various categories of boilers and heaters as shown in Table 3 of the SCAQMD Rule 2002, amended January 7, 2005. At that time, staff decided to keep the 2000 BARCT level at 25 ppmv for boilers/heaters with maximum input rating between 40-100 mmbtu/hr. In 2005, staff estimated about 51 boilers/heaters would have SCRs installed to reduce NOx emissions. As of today, only 4 of these equipment were retrofitted with SCRs in responses to the EPA consent degrees or order of abatement. None of these SCRs were installed in responses to the 2005 BARCT assessment. In the RECLAIM program, the refineries are allowed to purchase RTCs to cover their emissions in lieu of installing control equipment. If all boilers and heaters complied with the 2005 BARCT levels set by the SCAQMD under a command-and-control rule approach, then the emissions from boilers and heaters would be reduced from 7.39 tons per day to 1.92 tons per day, approximately 74% reduction in emissions.

Achieved-In-Practice NOx Levels for Boilers and Heaters

The following is a summary of refinery boilers and heaters that have very low emission levels:

- Fourteen process heaters using refinery fuel gas in the SCAQMD ranging from 22 to 653 mmbtu/hr equipped with Selective Catalytic Reduction (SCR) have achieved 1.6 - 3.5 ppmv NOx at 3% O_2;

- Two boilers, 400 HP and 1000 HP, using natural gas, equipped with LoTOx scrubbers have achieved 2 - 5 ppmv NOx at 3% O_2;

- A crude heater using refinery fuel gas rating at 10 mmbtu/hr in Coffeyville refinery Kansas has been operated at 3 - 8 ppmv NOx at 3% O_2 with Great Southern Flameless technology without the use of SCR.

All of the control technologies mentioned above are commercially available and can be designed to reach 2 ppmv NOx at 3% O_2.

Control Technology

Commercially available control technologies for NOx are Selective Catalytic Reductions (SCR), Great Southern Flameless Heaters, and LoTOx applications with scrubbers. Other potential technologies on the horizon are ClearSign, Cheng Low NOx and KnowNOx. SCR, Great Southern Flameless and ClearSign technologies are discussed below. Cheng Low NOx, LoTOx and KnowNOx technologiesare discussed in other Appendixes. Other common control technologies such as Low NOx burners, Ultra Low NOx burners or Selective Non Catalytic Reduction (SNCR) are not discussed here.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen through the following reactions. Please refer to Appendix A for further descriptions of the SCR technology.

For more than two decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available. In addition, the SCR technology is continuously evolved and advanced: new catalyst types such as ASC, low and high temperature catalysts have been developed to enhance the conventional SCR performance, and the SCR catalysts become more compact and durable. All SCR manufacturers that staff contacted confirm that SCRs can be designed to reduce 95%-98% NOx emissions from the refinery boilers and heaters to achieve 2 ppmv NOx while maintaining low ammonia slips of less than 5 ppmv. [3-15]

Great Southern Flameless Heaters

In 2012, Coffeyville Resources purchased the world's first flameless crude heater designed by Great Southern Flameless for their Coffeyville refinery in Kansas to comply with a Consent Decree issued by the U.S. EPA. The flameless heater has been in operation for over one year and has proven an achieved-in-practice performance of 5 ppmv NOx at 3% O2 with pilots in operation, and 3 ppmv NOx without pilots for flameless technology. Great Southern Flameless confirmed the following: [20-21]

- Flameless heaters can be designed to achieve:
  - 5 ppmv NOx at 3% O_2; or
  - 2 ppmv NOx at 3% O_2 with pilots off during flameless firing and with a fuel mix of 25% natural gas and 75% refinery gas.

- Oxy-fuel flameless heaters can be designed to achieve:
  - 2 ppmv NOx at 3% O_2; or

— 1 ppmv with pilots off during flameless firing

Great Southern Flameless can supply flameless heaters or oxy-fuel flameless heaters with maximum rating from 10 mmbtu/hr to 320 mmbtu/hr (240 mmbtu/hr process duty.) Their production capacity is 30 heaters per year. The modules are designed and fabricated in Oklahoma, shipped in pieces to be field, and assembled at the site. The heaters can use the same foundation of the conventional heaters. The flameless heater designed by Great Southern Flameless for the Coffeyville refinery has the following characteristic:

- The heater is a polygon with the process coil (heat exchanger tubes) in the center and two "Flameless Nozzle Grouping" (FNG) located on the wall which fire tangentially. Each FNG consists of 2 conventional nozzles, 2 flameless fuel nozzles, 4 air nozzles and 1 nozzle for pilot fuel.

- To pin the flue gas in circulation against the wall, Great Southern Flameless developed and patented a proprietary design for the heater's interior wall. The interior wall of the heater has a dimple pattern in the refractory which holds the flue gas to the wall and allows the flue gas to circulate in high volume and velocity around the heater until it eventually rotates out to the center of the heater, and up through the uptake ducts and into the convection section of the heater. This unique wall design eliminates hot gas impingement on the process coil located in the center of the heater and assures even heat radiation from the heater walls to the heat exchanger tubes.

- Great Southern Flameless also developed and has a patent pending for an automated 3-way switching valve. This valve allows the heater to be operated in three different firing modes:
  - Conventional firing mode when all fuel gas is diverted to the 2 conventional nozzles;
  - Staged firing mode when half of the fuel gas goes to the 2 conventional nozzles and the other half goes to the 2 flameless nozzles; and
  - Flameless firing mode when all fuel gas goes to the 2 flameless nozzles and the combustion is sustained by the high temperatures of the combustion air.

- The heater has a balanced draft air-preheat system which generates high temperature combustion air. High temperature combustion air is required for the staged firing mode and the flameless firing mode to maintain the high auto-ignition temperature required for combustion.

From cold start, the heater is brought up in natural draft mode in the same manner as any typical conventional heater. The firing rate of the heater is gradually increased to the required level while the combustion air is gradually increased to 850 degrees F. Once the combustion air temperature exceeds 850 degrees F, it will sustain the automatic ignition of fuel, and the heater is transitioned into the staged fuel firing mode with pilots off-line. The heater is operated in the staged firing mode until steady state operation is achieved. At this point, the heater is transitioned into flameless firing mode. Visible flame from the conventional nozzles disappears and NOx emissions decreases significantly in the flameless mode operation.

Table B.1 below tabulates the temperature profile inside the heater under the three modes of firing. With more even temperature distribution, the flameless firing mode results in 4 ppmv NOx compared to 77 ppmv NOx under conventional firing and 49 ppmv under staged firing mode. The Coffeyville heater average NOx emissions are in the levels of 3 – 8 ppmvd without the use of high temperature high energy SCR system. [16]

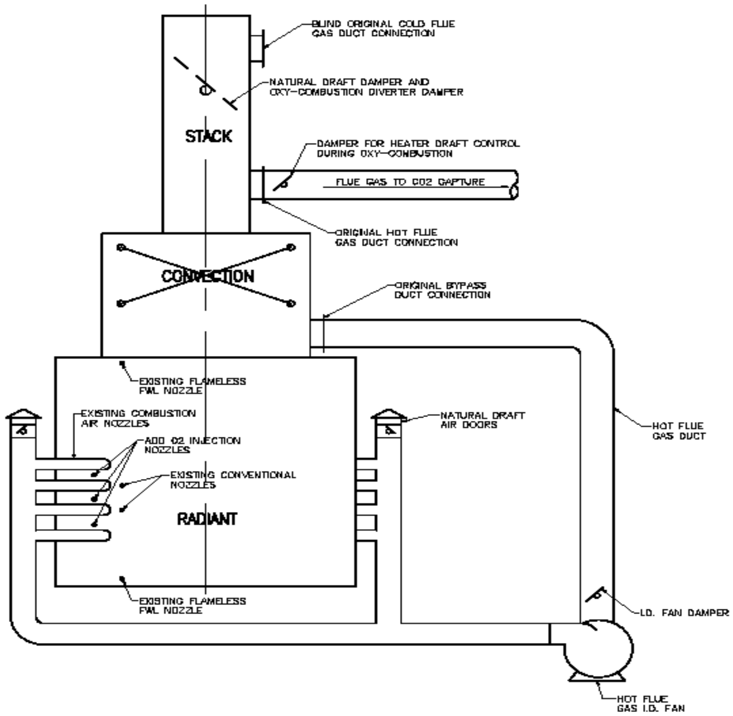
The heater can be designed for combustion with oxygen.[17] Combustion with oxygen in place of air will eliminate "prompt" NOx and reduce CO_2 emissions. Figure B.2 shows a flameless heater modified for oxygen combustion. Table B.2 lists the predicted performance of an oxy-flameless heater. Flameless and oxy-flameless heaters come in modules and can be stacked up to 320 mmbtu/hr rating.[18, 19]

Table B. 1– Temperature Zones and NOx Emissions of Great Southern Flameless Heater

	Conventional Firing	**Staged Firing**	**Flameless Firing**
Combustion Air Temperature, degrees F	804	893	909
Average Radiant Upper Level Temp, degrees F	1544	1740	1714
Average Radiant Mid Level Temp, degrees F	2050	1826	1476
Average Radiant Lower Level Temp, degrees F	1488	1627	1669
Excess Oxygen, %	3.7	2.6	2.4
NOx, lb/mmbtu	77	49	4

Table B. 2 – Predicted Performance of Great Southern Oxy-Flameless Heater

	Traditional Heater	**Flameless Heater**	**Oxy-Flameless Heater**
NOx, ppmv	31	4-8	0-1
Excess Oxygen, %	3	3	3
NOx, lb/mmbtu		0.0106	0.0021 or below



(Picture taken from Reference 17)

Figure B. 2 - Oxy-Flameless Heater

ClearSign Technology

ClearSign Combustion Corporation in Seattle has developed two technologies applicable for boilers and heaters: DUPLEX™ technology and Electrodynamic Combustion Control (ECC™). ClearSign expected that these technologies would generate a 1-digit NOx and CO without the need for flue gas recirculation (FGR), selective catalytic reduction (SCR), or high excess air operation.

DUPLEX™ technology can be installed in new boilers or heaters, or retrofit in existing boilers and heaters. The DUPLEX technology comprises a proprietary DUPLEX tile installed downstream of conventional burners. The hot combustion flame from the conventional burners impinges onto the DULEX tile, and the tile helps radiate heat evenly with high emissivity to the combustion products. DUPLEX operation also creates more mixing and shorter flames. Since the flame length is one parameter that limits the total heat release in a furnace, decreased flame length can allow for significantly higher process throughputs. DUPLEX tile is expected to have a 3- to 5-year life. A demonstration project with San Joaquin Air Pollution Control District and efforts of scaling up the technology to heaters of 5 - 50 million BTU/hr are underway. [20]

The Electrodynamic Combustion Control (ECC™) uses an electric field to effectively shape the flame, accelerate flame speed, and improve flame stability. The total electrical field power required to generate such effects is less than 0.1% of the firing rate. [20]

Emission performance from a bench test has been demonstrated for DUPLEX and ECC. NOx and CO were less than 5 ppmv, furnace temperatures were steady maintained between 1200 and 1800 degrees F. Beside the benefits of reducing air pollution, ClearSign believes that their burners will provide substantial economic benefits from more uniform heat distribution, improved process throughput, and potentially reduced maintenance costs. [22-23]

Costs and Cost Effectiveness for SCRs

Staff developed a Cost Curve that plots the PWV of the control devices as a function of boiler/heaters' maximum rating utilizing the following sets of data:

1. Refinery Survey Data
2. Refinery Consultant's Analysis
3. Data provided by three SCR manufacturers, Great Southern Flameless and ClearSign burners

Staff then used the PWVs from the "Cost Curve" to estimate the costs and cost effectiveness for all 212 boilers/heaters at the refineries. The details are explained below.

Survey Data

Staff conducted a refinery Survey in 2013. Through this Survey, the refineries reported cost information for their boilers and heaters operated with SCRs. There are 14 heaters at the refineries that currently achieve 1.6 ppmv to 3.5 ppmv NOx at 3% oxygen with the use of SCRs. The 2011 emissions, NOx concentrations measured at the stack, heaters' maximum rating, and the year of SCR installation are shown in Table B.3. Table B.3 also includes the equipment costs (in the year of installation), installation costs (in the year of installation), and annual operating costs reported by the refineries. [13] Marshall Index was used to bring the reported costs to the present dollars. Several heaters share a control device, and in this case, staff apportioned the reported costs for SCRs into individual SCR costs for each heater based on their relative maximum input ratings. The PWV of individual heaters are estimated using Equation 1 and 2.

PWV = (TIC + (15.62 x AC)) x Marshall Index (Equation 1)

Where:

PWV = Present Worth Value, \$
TIC = Total Installed Costs, \$

AC = Annual Operating Costs, $. The catalyst replacement costs were reported as a part of the annual operating costs

$PWV_{Heater\ A} = PWV * R_{Heater\ A} / R_{All\ Heaters}$ (Equation 2)

Where:

$PWV_{Heater\ A}$ = Present Worth Value of Heater A
$R_{Heater\ A}$ = Maximum Rating of Heater A
$R_{All\ Heaters}$ = Total Maximum Rating of All Heaters

From the set of data above, staff obtained the following ratios:

Installation Costs = 2.807 x Equipment Costs
Total Installed Costs = 3.870 x Equipment Costs
Present Worth Values = 4.072 x Equip Costs = 1.052 x Total Installed Costs (Equation 3)

Table B. 3 – Performance and Cost Information of SCRs for Process Heaters Collected from the Refinery Survey

	Device	Process Name	mmbtu/hr	2011 Emissions (lbs)	Control and Year of Installation	Existing NOx ppmv at 3%	Shared Control?
1	HEATER	CRUDE	85	837	SCR 08	3.5	no
2	HEATER	HYDROTREATING	28	2,577	SCR 07	2.7	yes
3	HEATER	HYDROTREATING	22	1,099	SCR 07	2.7	yes
4	HEATER	HYDROTREATING	13	834	SCR 07	2.7	yes
5	HEATER	COKING	176	34,119	SCR 92	2.7	yes
6	HEATER	COKING	176	34,296	SCR 92	2.7	yes
7	HEATER	COKING	176	41,579	SCR 92	2.7	yes
8	HEATER	CAT REFORM	177	2,152	SCR 94	1.6	yes
9	HEATER	CAT REFORM	125	1,779	SCR 94	1.6	yes
10	HEATER	CAT REFORM	88	1,068	SCR 94	1.6	yes
11	HEATER	CAT REFORM	199	2,855	SCR 94	1.6	yes
12	HEATER	H2 PRODUCTION	653	17,867	SCR 00	2.7	no
13	HEATER	CRUDE	83	1,726	SCR 01	2.7	no
14	HEATER	HYDROTREATING	78	539	SCR 03	2.3	no

	Equipment Costs ($)	Installation Costs ($)	Total Installed Costs ($)	Annual Operating Costs ($)	Marshall Index	PWV (million)
1	760,000	720,000	1,480,000	74,000	1.09	2.873
2	415,000	175,000	590,000	89,000	1.13	0.994
3	415,000	175,000	590,000	89,000	1.13	0.788
4	415,000	175,000	590,000	89,000	1.13	0.455
5	2,275,000	6,825,000	9,100,000	48,000	1.64	5.385
6	2,275,000	6,825,000	9,100,000	48,000	1.64	5.385
7	2,275,000	6,825,000	9,100,000	48,000	1.64	5.385
8	1,950,000	5,850,000	7,800,000	30,000	1.56	3.877
9	1,950,000	5,850,000	7,800,000	30,000	1.56	2.736
10	1,950,000	5,850,000	7,800,000	30,000	1.56	1.928
11	1,950,000	5,850,000	7,800,000	30,000	1.56	4.359
12	7,650,000	22,950,000	30,600,000	30,000	1.42	44.117
13	7,500,000	22,500,000	30,000,000	30,000	1.42	43.265
14	4,975,000	14,925,000	19,900,000	30,000	1.38	28.109

Refinery's Consultant Study

A refinery provided staff information from a study conducted by their consultant. This study estimated actual costs to install SCRs for 18 heaters at the refinery. The heaters have capacity ranging from 39 - 352 mmbtu/hr. Several heaters were to share a common SCR. Using the refinery consultant's estimates for the total installed costs and a multiplier factor of 1.052 shown in Equation 3, staff estimated the PWVs for these 18 heaters. Staff then apportioned the PWVs of common SCRs into individual SCR costs for individual heaters using the heater maximum ratings. The PWVs for 18 heaters are summarized in Table B.4. [14]

Table B. 4 – Costs of SCRs Estimated Based on Information Submitted by Refinery

No	Device	Process Name	mmbtu/hr	2011 Emissions (lbs)	Existing NOx (ppmv)	Shared Control?	PWV for SCR (million)
1	HEATER	FCCU	51	27,006	59	yes	2.557
2	HEATER	FCCU (same stack)	39	16,482	59	yes	1.956
3	HEATER	CRUDE	350	137,192	33		6.838
4	HEATER	CRUDE	154	31,639	20		6.017
5	HEATER	CAT REFORM	116	20,646	33	yes	3.894
6	HEATER	CAT REFORM	68	14,629	33	yes	2.283
7	HEATER	CAT REFORM	71	10,242	33		2.383
8	HEATER	CAT REFORM	56	12,183	33	yes	1.880
9	HEATER	CAT REFORM	19	1,591	33	yes	0.638
10	HEATER	CAT REFORM	110	97,278	75	yes	3.696
11	HEATER	CAT REFORM	100	32,333	75	yes	3.360
12	HEATER	CAT REFORM	70	51,462	75	yes	2.352
13	HEATER	CAT REFORM	42	42,312	75	yes	1.411
14	HEATER	CAT REFORM	24	26,193	75	yes	0.806
15	HEATER	H2 PRODUCTION	340	140,640	34		20.409
16	BOILER 11	STEAM GEN	352	117,971	56		15.044
17	BOILER 8	STEAM GEN	179	64,968	85		9.994
18	BOILER 6	STEAM GEN	250	123,212	75		12.203

SCR Manufacturers

All SCR manufacturers that staff contacted confirmed the following:

— It is feasible to achieve 2 ppmv NOx at 5 ppmv ammonia slip; and
— The costs for SCRs to achieve 2 ppmv NOx is about 10% higher than the costs of SCRs to meet 5 ppmv NOx.

Three SCR manufacturers provided staff with SCR equipment costs, and in December 2014 staff used a multiplication factor of 4 to estimate the PWVs as shown in Equation 3 based on the actual reported costs from several refineries in response to the Survey conducted by the SCAQMD.

In March 2015, after the refinery visits, staff used a multiplication factor of 4 to estimate the TICs (not PWVs) as recommended by several refineries to reflect the difficulty of installing SCR for retrofit applications. [15-17] In addition, staff added the following costs to the TICs of the SCRs in Table B.5:

— Induced draft fans: $1.26 M for 100 mmbtu/hr heater, $1.69 M for 163 mmbtu/hr, and $2.67 M for 350 mmbtu/hr as estimated by NEC [24]
— Ammonia tanks: $1.5 M as estimated by NEC [24]
— CEMS: $100,000 based on data submitted to SCAQMD in previous CEMS applications

Table B. 5 - Costs of SCRs Estimated Based on Information from SCR Manufacturers

	Unit Rating (mmbtu/hr)	NOx in (ppmv)	NOx out (ppmv)	Equip Cost ($ M)	PWV ($ M)	NH3 (lb/hr)
Manufacturer A	163	80	2	0.13	0.52	10
	163	80	2	0.10 (NH_3 Slip Cat)	0.4	10
Manufacturer B	100	100	5	0.27 (note 1)	1.08	17
	100	100	2	0.30	1.30	17.5
	350	100	5	0.325 (note 2)	1.30	57
	350	100	2	0.375	1.50	59
Manufacturer C	100	100	5	0.20 (note 3)	0.80	5.8
	100	100	2	0.22	0.88	6.0
	350	100	5	0.65 (note 4)	0.26	17.5
	350	100	2	0.70	0.28 (note 5)	17.8

Note: 1) SCR replacement costs were estimated to be $10,000 - $15,000 every 3 – 5 years; 2) SCR replacement costs were estimated to be $20,000 - $25,000 every 3 – 5 years; 3) SCR replacement costs were estimated to be $23,000 - $24,000 every 6 to 7 years ; 4) SCR replacement costs were estimated to be $70,000 - $72,000 every 6 to 7 years; 5) Manufacturer C also estimated annual operating costs based on ammonia costs of about $800 per ton, and using this data, the PWV of the SCR for the 350 mmbtu/hr heater to meet 2 ppmv would be $2,218,040 million which is in the range of $2,800,000 estimated by using the multiplier factor of 4 and the equipment costs provided by the manufacturer. 6) Ammonia slip is 5 ppmv in all categories listed in Table B-6

Great Southern Flameless

Great Southern Flameless provided costs data based on the following assumptions, and the results are summarized in Table B.6 and Table B.7. [20-21]

- 5 ppmv NOx outlet concentration for standard flameless heater
- 3 ppmv NOx outlet for standard flameless heater with pilots off during flameless firing
- 2 ppmv NOx outlet for standard flameless heater with pilots off during flameless firing and fuel conditioning (25% natural gas and 75% fuel gas)
- 1 ppmv NOx outlet concentration for standard oxy-fueled flameless heater
- The equipment costs include burner management system (BMS) control
- Oxygen costs is estimated at $70 per ton for 93% oxygen concentration
- There is no difference in costs between the 2 ppmv and 5 ppmv NOx flameless heaters
- The PWV was estimated based on 4% interest rate and 20-25 years life for heaters
- The PWV for standard flameless includes the savings due to increase in efficiency (83% to 91%) over the conventional heaters
- The PWV for standard oxy-fuel flameless is based on 20% (mass) injection of O2 and includes the savings due to operating efficiency increase (83% to 93.5%)

Table B. 6 – Costs for Great Southern Flameless Heaters

Fired Duty HHV (mmbtu.hr)	Equipment Costs ($)	Installation Costs ($)	Total Installed Costs ($)
32	1,909,005	3,818,010	5,727,015
117	3,813,040	7,626,080	11,439,120
187	4,345,000	8,690,000	13,035,000
321	5,332,800	10,665,600	15,998,400

Table B. 7 - Costs for Great Southern Flameless Heaters with Fuel Savings

Fired Duty HHV (mmbtu/hr)	PWV for Flameless Heater 2 ppmv NOx ($ M)	PWV for Oxy-Fuel Flameless 1 ppmv NOx ($ M)
32	4.9	10
117	7.8	22
187	7.0	32
321	5.5	50

ClearSign

ClearSign provided the estimates summarized in Table B.8 for DUPLEX burners to achieve 5 ppmv NOx and also 2 ppmv NOx. Note that their estimates did not yet include the economic benefits for more uniform heat distribution or improved process throughput and potential reduced maintenance costs. ClearSign indicated that their cost estimates were highly conservative and can be adjusted due to market demand. In addition, ClearSign provided an analysis showing the revenue savings of about $36,000 per ton NOx reduced using DUPLEX burners compared to SCR to achieve the proposed BARCT levels. [23]

Table B. 8 - Costs for DUPLEX Burners

Maximum Input Rating (mmbtu/hr)	PWV for 2 ppmv DUPLEX ($ M)	PWV for 5 ppmv DUPLEX ($ M)
12	0.442	0.102
24	0.884	0.204
48	1.767	0.408
96	3.535	0.815
150	5.523	1.274
200	7.292	1.682
400	14.728	3.397

Present Worth Values and Cost Effectiveness

Finally, staff constructed a curve showing the PWVs for the control devices as a function of boiler/heaters' maximum rating using the five sets of data shown above. Refer to Figure B.3. Staff then estimated the PWVs for each boiler/heater using the upper-bound values:

For 5 ppmv SCR:

5 million dollars for ≤ 100 mmbtu/hr boilers and heaters
10 million dollars for > 100 – 200 mmbtu/hr boilers and heaters
20 million dollars for > 200 – 400 mmbtu/hr boilers and heaters
30 million dollars for > 400 – 600 mmbtu/hr boilers and heaters
45 million dollars for > 600 mmbtu/hr boilers and heaters

For 2 ppmv SCR:

\$5.5 M for units with maximum rating ≤ 100 mmbtu/hr
\$11 M for units with maximum rating > 100 – 200 mmbtu/hr
\$22 M for units with maximum rating > 200 – 400 mmbtu/hr
\$33 M for units with maximum rating > 400 – 600 mmbtu/hr
\$49.5 M for units with maximum rating > 600 mmbtu/hr

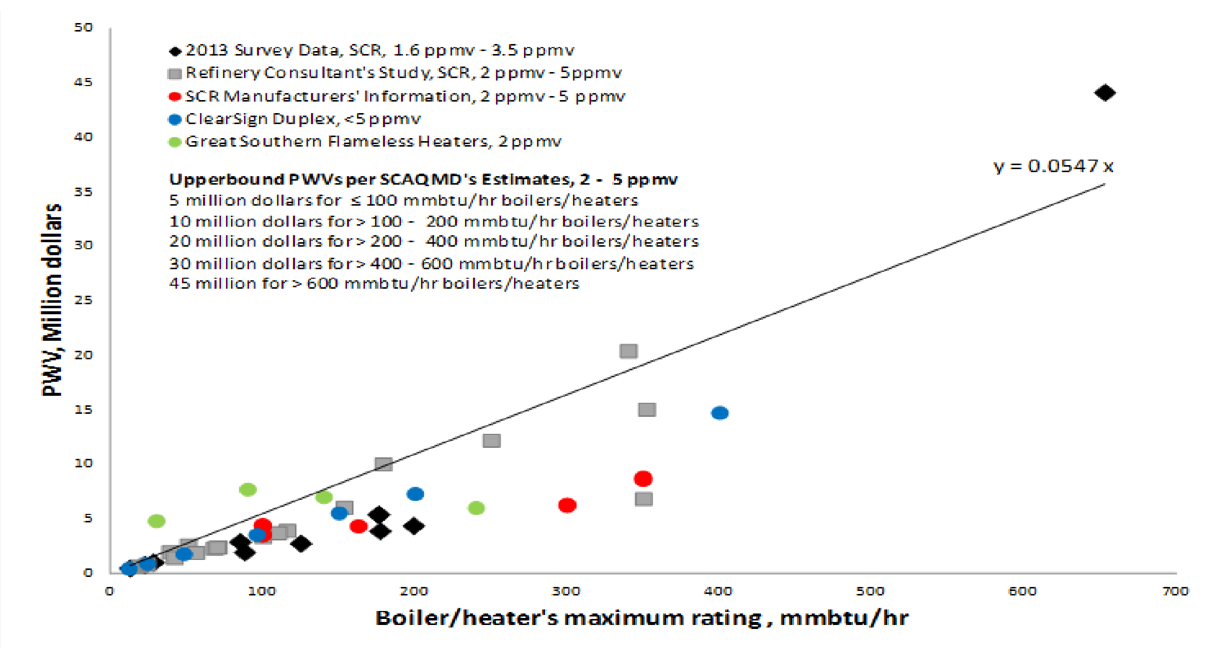


Figure B. 3 – Revised PWVs of Control Devices for Refinery Boilers/Heaters (March 2015)

Incremental Cost Effectiveness was estimated as follows based on the Discounted Cash Flow (DCF) method. A multiplication factor of 1.65 was used to estimate the cost effectiveness using the Levelized Cash Flow (LCF) method:

CE = PWV / (ER x 365 days x 25 years)

Where:

CE = Incremental Cost Effectiveness, \$/ton
PWV = Present Worth Value, \$
ER = Incremental Emission Reductions, tpd

Units with low cost effectiveness (>50 K per ton) were excluded from estimating the total emission reductions and average cost effectiveness for the category of boilers and heaters. Staff estimated there would be about 103 units that would be cost effective with total PWVs of \$254.5 Million and an average cost effectiveness of \$27 K per ton NOx reduced as of December 2014.

Consultant's Analysis for SCRs and Staff's Revised Estimates for SCRs

The consultant NEC concurred that the 2 ppmv BARCT level is feasible for refinery boilers/heaters >40 mmbtu/hr. However, NEC recommended using SCRs with 4 layers of catalysts and 44-ft high to meet the 2 ppmv BARCT level. [24] NEC estimated the costs based on the costs provided by a manufacturer for a FCCU's SCR. The costs estimated by NEC were about 3-4 times higher than staff's estimates and as a result only 48 heaters/boilers became cost-effective under the NEC's analysis. A comparison between NEC and staff's results are tabulated in Table B.9 below.

Table B. 9 - Comparison of NEC's and Staff's Cost Estimates for SCRs (December 2014)

	Staff's Estimates	**Staff's Estimates with NEC's Cost Information**
Total Boilers and Heaters	212	212
No of Cost-Effective Units	103	48
Total PWVs for Cost-Effective Units	\$254.5 M	\$162 M
Total Emission Reductions	1.05 tpd	0.61 tpd
Average Cost Effectiveness	\$27 K per ton DCF	\$29K per ton DCF

Staff's review of NEC's analysis is shown in Appendix G. Staff used a different approach than NEC to estimate the SCR costs for boiler and heaters. In addition, staff agreed with the following three recommendations from the refineries as well as NEC, and revised its cost analysis accordingly:

1. NEC and staff visited about 100 boilers and heaters at the refineries. NEC identified about several heaters with space congestion difficulties (1 heater @ 527 mmbtu/hr, 1 heater @ 69 mmbtu/hr, and 4 heaters @ 160 - 190 mmbtu/hr). Staff agreed with NEC's recommendation and revised the estimates to exclude these heaters from further cost analysis.

2. The refineries requested staff to use a factor of 4 (not of 3, which was a combination of the 1.86 factor recommended in the EPA OAQPS Guidelines and 50% added contingency) to estimate the installed costs from the equipment costs provided by the manufacturers. Staff agreed with this recommendation and revised the PWVs calculated based on the manufacturers' information. Revised PWVs are included in Figure B.3 above.

3. For heaters <110 mmbtu/hr with existing SCRs, the refineries requested staff to consider the full costs of SCR installations, not the "incremental" costs in estimating the cost effectiveness values. Staff concurred with this request.

Staff's revised estimate is summarized in Table B.10. The details are included in Table B.11. Using the linear best-fit equation PWV = 0.0547 x maximum rating of boiler/heater for 5 ppmv SCRs, and add 10% to reflect PWV for 2 ppmv SCRs will results in slightly higher incremental emission reductions and less costs.

Table B. 10 – Revised Cost Estimates of SCRs for Boilers and Heaters (March 2015)

Total Boilers and Heaters	212
No of Cost-Effective Units (<50,000 $/ton)	83
No of SCRs	76 (25 upgraded, 51 new)
Total PWVs for Cost-Effective Units	242
Total Emission Reductions	0.96 ton per day
Average Cost Effectiveness	27,529 $/ton DCF, 45,422 $/ton LCF

Staff's Recommendation

Staff proposes to set a new BARCT level of 2 ppmv NOx for refinery boilers/heaters >40 mmbtu/hr because NOx control technologies such as SCR, LoTOx, Great Southern Flameless heaters are either commercially available, achieved-in-practice and/or can be designed to achieve 2 ppmv NOx in a cost-effective manner.

A summary of staff's analysis is tabulated in Tables B.11 and B.12:

Incremental Emission Reductions beyond 2005 BARCT level = 0.96 tons per day
Total Incremental Costs = $ 242 M
Average Incremental Cost Effectiveness = $28 K/ton (DCF) and $45 K/ton LCF)

Table B. 11 – Details of Cost Estimates for Boilers and Heaters (March 2015)

Summary of CE for Boilers/Heaters

<u>Results:</u>

Total units = 23 boilers + 189 heaters = 212 units

Cost-effective units = 83. Not cost-effective units = 129

Total SCRs = 76 (25 upgraded, 51 new)

Total PWVs = 242 millions. Total emission reductions = 0.96 tpd.

Average cost effectiveness = 27,529 $/ton DCF = 45,422 $/ton LCF

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
1	6	925	HEATER	H2 PRODUCTION	931	0.06	0.03	49.50	45.00	4.50	19,066	SCR 87	5.65
2	5	3530	HEATER	H2 PRODUCTION	653	0.02	0.02	49.50	45.00	4.50	30,425	SCR 00	2.69
3	1	570	HEATER	H2 PRODUCTION	650	0.10	0.02	49.50	45.00	4.50	20,782	SCR 85, LNB 6	12.66
4	1	27	HEATER	CRUDE	550	0.13	0.02	33.00	30.00	3.00	17,671	LNB 97	21.18
5	6	913	HEATER	CRUDE	457	0.09	0.01	33.00	30.00	3.00	21,995	SCR 92	13.68
6	1	1465	HEATER	H2 PRODUCTION	427	0.03	0.01	33.00	30.00	3.00	24,476	SCR, LNB 95	7.25
7	5	641	HEATER	HYDROCRACKING	365	0.18	0.02	22.00	20.00	2.00	13,703	LNB 99	27.69
8	8	429	BOILER	STEAM GEN/SCR09	352	0.03	0.01	22.00	20.00	2.00	25,992	SCR 2009	6.00
9	8	430	BOILER 11	STEAM GEN	352	0.16	0.01	22.00	20.00	2.00	27,891		
10	8	59	HEATER	CRUDE	350	0.19	0.01	22.00	20.00	2.00	16,363		
11	7	220	HEATER	H2 PRODUCTION	350	0.08	0.01	22.00	20.00	2.00	22,064	SCR 1990	21.66
12	5	2216	BOILER	STEAM GEN	342	0.11	0.01	22.00	20.00	2.00	22,257	SCR 88	47.16
13	6	1236	BOILER	STEAM GEN	340	0.01	0.01	22.00	20.00	2.00	23,944	SCR 97	6.76
14	8	210	HEATER	H2 PRODUCTION	340	0.19	0.01	22.00	20.00	2.00	25,457		
15	6	1239	BOILER	STEAM GEN	340	0.02	0.01	22.00	20.00	2.00	27,239	SCR 97	7.75
16	5	82	HEATER	CRUDE	315	0.02	0.01	22.00	20.00	2.00	18,018	SCR 91	5.69
17	5	83	HEATER	CRUDE	315	0.02	0.01	22.00	20.00	2.00	19,885	SCR 91	5.69
18	1	535	HEATER	CAT REFORM	310	0.07	0.01	22.00	20.00	2.00	27,440	LNB 94	22.84
19	6	803	BOILER	STEAM GEN	309	0.21	0.01	22.00	20.00	2.00	41,496	LNB 86	104.00
20	7	686	BOILER 7	STEAM GEN	304	0.02	0.01	22.00	20.00	2.00	31,442	SCR 2009	8.50
21	1	63	HEATER	CRUDE	300	0.01	0.01	22.00	20.00	2.00	24,097	SCR, LNB 94	4.81
22	6	805	BOILER	STEAM GEN	291	0.19	0.01	22.00	20.00	2.00	42,085	LNB 88	74.91
23	1	532	HEATER	CAT REFORM	255	0.04	0.01	22.00	20.00	2.00	34,138	LNB 01	16.64
24	7	688	BOILER 6	STEAM GEN	250	0.17	0.01	22.00	20.00	2.00	42,403		
25	9	1550	BOILER/ne	STEAM GEN	245	0.02	0.01	22.00	20.00	2.00	26,507	SCR 2008	5.39
26	5	643	HEATER	HYDROCRACKING	220	0.04	0.01	22.00	20.00	2.00	31,409	LNB 99	19.63
27	5	84	HEATER	CRUDE	219	0.02	0.01	22.00	20.00	2.00	23,986	SCR 91	5.69
28	5	20	HEATER	CRUDE	217	0.06	0.01	22.00	20.00	2.00	31,482	LNB 01	23.16
29	9	430	HEATER	HYDROTREATING	200	0.02	0.01	11.00	10.00	1.00	12,602	SCR	8.43
30	4	9	HEATER	CRUDE	199	0.10	0.01	11.00	10.00	1.00	14,133	SCR	31.91 - 41.32
31	5	3031	HEATER	CAT REFORM	199	0.00	0.01	0.00	0.00	0.00	0	SCR 94	1.64

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
32	7	687	BOILER 8	STEAM GEN	179	0.09	0.00	11.00	10.00	1.00	25,410		
33	5	471	HEATER	CAT REFORM	177	0.00	0.00	0.00	0.00	0.00	0	SCR 94	1.64
34	5	161	HEATER	COKING	176	0.06	0.01	11.00	10.00	1.00	18,504	SCR 92	2.71
35	5	159	HEATER	COKING	176	0.05	0.01	11.00	10.00	1.00	18,504	SCR 92	2.71
36	5	160	HEATER	COKING	176	0.05	0.01	11.00	10.00	1.00	20,355	SCR 92	2.71
37	8	104	HEATER	COKING	175	0.05	0.00	11.00	10.00	1.00	22,645		
38	8	105	HEATER	COKING	175	0.05	0.00	11.00	10.00	1.00	24,004		
39	6	914	HEATER	CRUDE	161	0.04	0.01	11.00	10.00	1.00	17,704	SCR 92	13.70
40	8	78	HEATER	CRUDE	154	0.04	0.01	11.00	10.00	1.00	21,401		
41	8	79	HEATER	CRUDE	154	0.04	0.00	11.00	10.00	1.00	23,180		
42	1	29	HEATER	CRUDE	150	0.05	0.00	11.00	10.00	1.00	26,662	LNB 94	35.74
43	4	388	HEATER	HYDROCRACKING	147	0.12	0.01	11.00	10.00	1.00	20,879	SCR	49.6 - 73.5
44	4	1122	BOILER	H2 PRODUCTION	140	0.01	0.00	11.00	10.00	1.00	26,106	SCR	7.7 - 8.1
45	9	6	HEATER	CRUDE	136	0.04	0.01	11.00	10.00	1.00	21,766		19.31
46	7	264	HEATER	HYDROCRACKING	135	0.05	0.00	11.00	10.00	1.00	35,517		
47	1	155	HEATER	COKING	130	0.05	0.00	11.00	10.00	1.00	33,211	LNB 00	39.55
48	1	31	HEATER	CRUDE	130	0.04	0.00	11.00	10.00	1.00	35,015	LEA 01	29.21
49	1	153	HEATER	COKING	130	0.04	0.00	11.00	10.00	1.00	36,700	LNB 97	36.14
50	1	151	HEATER	COKING	130	0.04	0.00	11.00	10.00	1.00	37,286	LNB 97	39.39
51	6	930	HEATER	HYDROCRACKING	129	0.06	0.00	11.00	10.00	1.00	36,151	ULNB 95	55.12
52	9	378	BOILER	STEAM GEN	128	0.01	0.01	11.00	10.00	1.00	20,725	SCR	5.17
53	6	120	HEATER	COKING	126	0.05	0.00	11.00	10.00	1.00	38,824	LNB 95	51.79
54	5	472	HEATER	CAT REFORM	125	0.00	0.00	0.00	0.00	0.00	0	SCR 94	1.64
55	1	67	HEATER	CRUDE	120	0.04	0.01	11.00	10.00	1.00	20,294	LNB 94	34.37
56	4	90	HEATER	FCCU	127	0.06	0.00	11.00	10.00	1.00	44,113	LNB	46.6 - 52.1
57	3	77	BOILER	STEAM GEN	112	0.05	0.00	11.00	10.00	1.00	44,197		
58	3	76	BOILER	STEAM GEN	112	0.05	0.00	11.00	10.00	1.00	44,197		
1	9	768	HEATER	HYDROTREATING	110	0.02	0.04	11.00			31,494	SCR	9.43
2	7	154	HEATER	CAT REFORM	110	0.13	0.03	11.00			41,628		
3	5	451	HEATER	HYDROTREATING	102	0.10	0.03	11.00			40,338	no control	99.31
4	1	33	HEATER	CRUDE	100	0.02	0.02	5.50			25,116	LNB 94	22.79
5	7	155	HEATER	CAT REFORM	100	0.04	0.01	5.50			47,328		
6	9	22	HEATER	COKING	95	0.02	0.02	5.50			29,430		20.33
7	4	89	HEATER	FCCU	95	0.05	0.08	5.50			7,718	LNB	46.6 - 52.1
8	6	269	HEATER	HYDROTREATING	94	0.03	0.01	5.50			44,210	LNB 88	34.10
9	6	918	HEATER	COKING	91	0.08	0.02	5.50			34,411	LNB 91	91.70
10	6	917	HEATER	COKING	91	0.07	0.02	5.50			38,067	LNB 98	82.07
11	1	250	HEATER	FCCU	89	0.02	0.02	5.50			32,240	LNB 95	27.87
12	5	473	HEATER	CAT REFORM	88	0.00	0.02	0.00			0	SCR 94	1.64

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
13	5	3695	HEATER	CRUDE	83	0.00	0.03	5.50			21,488	SCR 01	2.70
14	7	146	HEATER	HYDROTREATING	76	0.02	0.01	5.50			43,097		
15	6	85	HEATER	COKING	74	0.06	0.01	5.50			45,265	LNB 88	97.00
16	8	174	HEATER	HYDROTREATING	70	0.06	0.02	5.50			35,422		
17	9	53	HEATER	HYDROTREATING	68	0.01	0.02	5.50			32,565		16.43
18	6	84	HEATER	COKING	67	0.04	0.01	5.50			44,780	LNB 85	116.81
19	6	83	HEATER	COKING	67	0.05	0.01	5.50			45,124	LNB 88	103.95
20	4	770	HEATER	HYDROTREATING	63	0.00	0.02	5.50			32,156	SCR	5.5 - 6.4
21	5	625	HEATER	HYDROCRACKING	63	0.06	0.01	5.50			47,614	no control	90.40
22	7	194	HEATER	HYDROTREATING	60	0.05	0.02	5.50			39,909		
23	4	218	HEATER	CAT REFORM	60	0.02	0.01	5.50			40,392	LNB	29.8 - 32.2
24	5	619	HEATER	HYDROCRACKING	57	0.05	0.01	5.50			45,968	no control	95.47
25	5	617	HEATER	HYDROCRACKING	57	0.05	0.01	5.50			40,839	no control	84.24

Summary

	tpd		
>110	0.44		93.50
40-110	0.52	148.50	
Total Units	0.96		
Total costs		242	
Average CE	27,529		

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Appendix C – Refinery Gas Turbines

Process Description

Gas turbines are used in refineries to produce both 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%. Aero-derivative 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 existing gas turbines at the refineries in the SCAQMD range from 7 MW to 83 MW. Most are all operated with duct burners, heat recovery steam generator (HRSG), Selective Catalytic Reduction (SCR), CO catalysts and some units have Ammonia Slip Catalysts (ASC), Cheng Low NOx (CLN), and Dry Low NOx (DLN) or Dry Low Emissions (DLE) combustors. Figure C.1 shows a typical layout of a turbine, duct burner, HRSG, and control system.

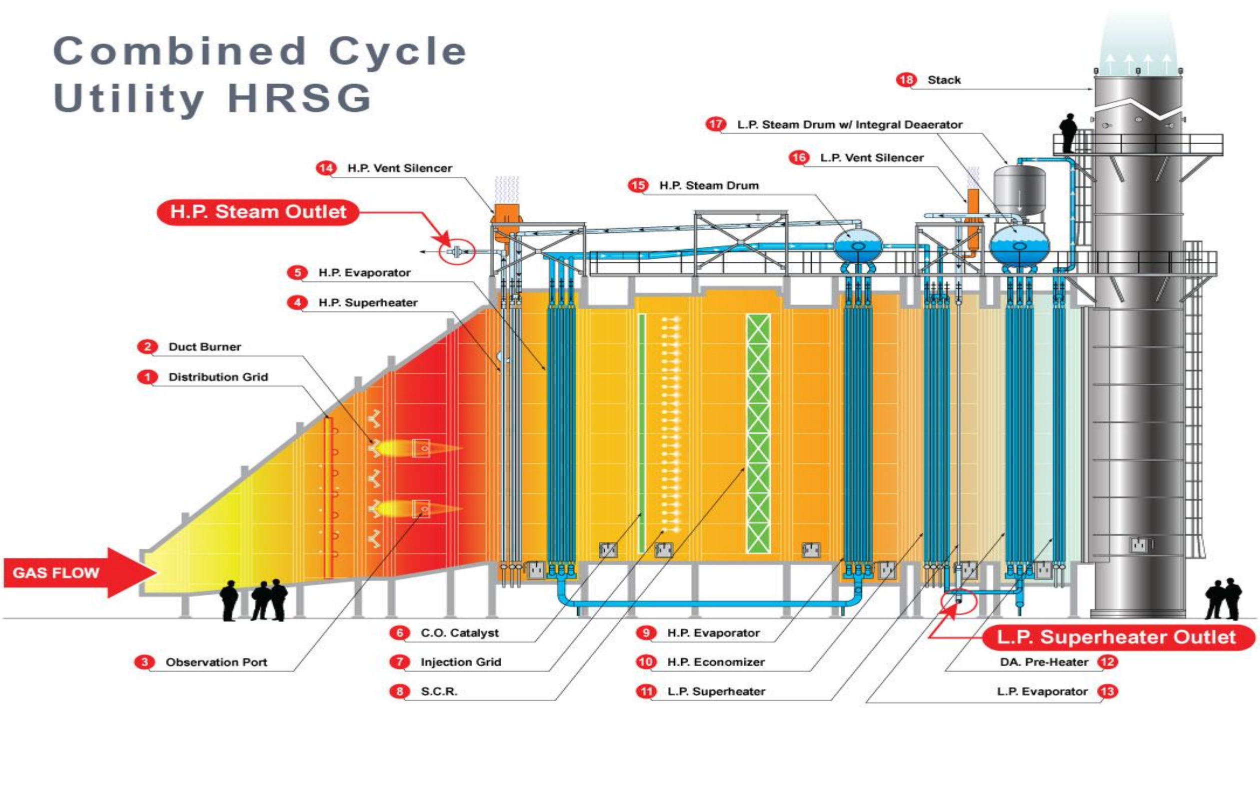


Figure C. 1 - Gas Turbine with Duct Burner

Emission Inventory

There are a total of 21 gas turbines/duct burners classified as major NOx sources at the refineries in the SCAQMD. Collectively, the 21 gas turbines/duct burners emitted about 1.33 tons per day in 2011 as shown in Table C.1. Their NOx levels at the stack vary from 1.67 ppmv at 15% O2 for units with SCR and ASC to 5.95 ppmv for units with SCR and water injection. [1]

It should be noted that at the inception of the RECLAIM program, the SCAQMD provided allocations for the gas turbines based on the 2000 BARCT level of 62.27 lbs/mmscft. If all gas turbines/duct burners were operated at the 2000 BARCT level of 62.27 lb/mmscft, the emissions from these turbines would amount to about 4.86 tons per day. In addition, these units are subject to either BACT limits or permit conditions that limit the annual mass emissions at the time the permit were issued: Refinery 1's gas turbines/duct burners have a BACT limit of 8 ppmv NOx; Refinery 5, 6 and 7's units have a BACT limit of 9 ppmv; and units at Refinery 4 are subject to a limit of 583 tons per year of NOx emissions. If these gas turbines/duct burners were operated at the BACT levels or at the levels specified in the permit conditions at the time the permits were issued, the emissions would be 5.99 tons per day, higher than 4.86 tons per day of the 2000 BARCT. All of the gas turbines are currently emitting at a level below their allocations and below the levels at the time their permits were issued. Technology improves with time and the BACT levels have recently changed to 2 ppmv for frame turbines and 2.5 ppmv for aero-derivative units.

Achieved-In-Practice NOx Levels for Gas Turbines

- Refinery 10's 7 MW aero-derivative gas turbine/duct burner with Cormetech SCR and ASC operating under a permit condition of 2.5 ppmv NOx, 15% O_2 has actually achieved the levels below 2 ppmv NOx at 15% O_2. [1, 6, 9, 25]

- In 2010, Refinery 5 received a permit to construct a new 46 MW frame gas turbine/duct burner with DLN, SCR and CO catalysts. The permit has a limit of 2 ppmv NOx, 15% O_2 and 5 ppmv NH3 slip. This unit has been in operation since 2012. [28-29]

- In 2011, Refinery 1 received a permit to construct for a 85 MW gas turbine /duct burner with DLN, SCR and CO catalyst. The permit had a permit condition required the turbine to be operated at a BACT level of 2 ppmv NOx, 15% O2. Due to various reasons, Refinery 1 did not install the gas turbine. [7]

The above 7 MW aero-derivative, 46 MW and 85 MW frame gas turbines/duct burners have proven that it is feasible to propose a level of 2 ppmv NOx, 15% O2, annual average, for gas turbines using natural gas as well as refinery gas. It is worth to mention that limits stated in the permit conditions are based on short-term averages (e.g. 1-hour average), and that a 2 ppmv, 1-hour average, can be more stringent than the proposed BARCT at 2 ppmv, annual average.

Table C. 1 - 2011 Emissions for Refinery Gas Turbines/Duct Burners

	Fac ID	Device ID	Device	mmbtu/hr	MW	Turbine Type	2011 Emissions (lbs)	Control & Year	Existing ppmv NOx at 15% O2
1	1	1226	Turbine	986	83	GE	78,418	DLE, SCR, CO, 88	2.80
5	1	1227	Duct Burner	340			27,097	SCR, CO, 88	2.80
2	1	1233	Turbine	986	83	GE	69,996	SCR, CO 98	3.50
6	1	1234	Duct Burner	340			22,034	SCR, CO 98	3.50
3	1	1236	Turbine	986	83	GE	72,933	SCR, CO, 88	2.53
7	1	1237	Duct Burner	340			21,090	SCR, CO, 88	2.53
4	1	1239	Turbine	986	83	GE	85,228	SCR, CO, 88	2.52
8	1	1240	Duct Burner	340			15,262	SCR, CO, 88	2.52
9	6	926	Turbine	316	23	GE	110,546	SCR, 87	5.65
10	4	810	Turbine	392	30	Pratt Whitney	55,264	SCR, CO, WI	5.95
11	4	812	Turbine	392	30	Pratt Whitney	50,084	SCR, CO, WI	4.82
12	7	828	Turbine	646	59	Westinghouse	118,842	SCR, 86	5.65
13	7	829	Duct Burner	99			16,191	SCR, 86	5.65
14	5	2198	Turbine A	560	46	GE Frame6	73,759	SCR, 95	4.20
15	5	2199	Duct Burner	120			7,521	SCR, 95	4.20
16	5	2207	Turbine B	560	46	GE Frame6	61,809	SCR, 95	3.46
17	5	2208	Duct Burner	120			9,569	SCR, 95	3.46
18	5	3053	Turbine C	506	46	GE Frame6	68,408	SCR, 96	4.24
19	5	3054	Duct Burner	286			5,686	SCR, 96	4.24
20	10	677	Turbine	90	7	Solar, Taurus	1,598	SCR, ASC, 03	1.67
21	10	679	Duct Burner	50		Solar, Taurus	430	SCR, ASC, 03	1.67
						Total (tpd)	**1.33**		

Control Technology

Gas turbines/duct burners are capable of emitting very low NOx emission levels. Currently most of the units at the refineries in SCAQMD are emitting less than 5 ppmv NOx using commercially available control technologies such as water or steam injection, DLN, DLE, CLN, SCR, CO catalysts and ASC.

Water or Steam Injection

Most of the NOx generated in the gas turbine/duct burner is "thermal" NOx. Water or steam injected into the high temperature frame zone quench the temperature down and reduce NOx to approximately 25 ppmv at 15% O2. Water/steam injection however tends to increase the CO emissions appreciably.

Dry Low NOx (DLN) and Dry Low Emissions (DLE)

DLN/DLE is based on a concept of lean premixed combustion – gaseous fuel is premixed with combustion air at the air to fuel ratio two times higher than the stoichiometric ratio. The lean mixture reduces peak flame temperature in the combustion zone and suppresses "thermal" NOx formation. The premixing chamber for the combustion air and gaseous fuel must be specifically designed for each type of turbines and integrally integrated into the turbine design. Every 4 to 5 years, the combustion liners of the DLE/DLN combustors are deteriorated and must be replaced. Table C.2 shows potential performance of DLN/DLE in certain models of GE frame and aero-derivative turbines. A few models of turbines can reach as low as 3-5 ppmv NOx natural gas fired. Maintaining the low NOx emission levels from the turbines from full to low load, or from turbines with varying load swings coupled with the emissions from the duct burners remain a challenge for DLN/DLE combustor technology. Most manufacturers would guarantee a level of 15-25 ppmv for DLE/DLN combustors. [14-16]

Table C. 2 – Performance of DLN and DLE

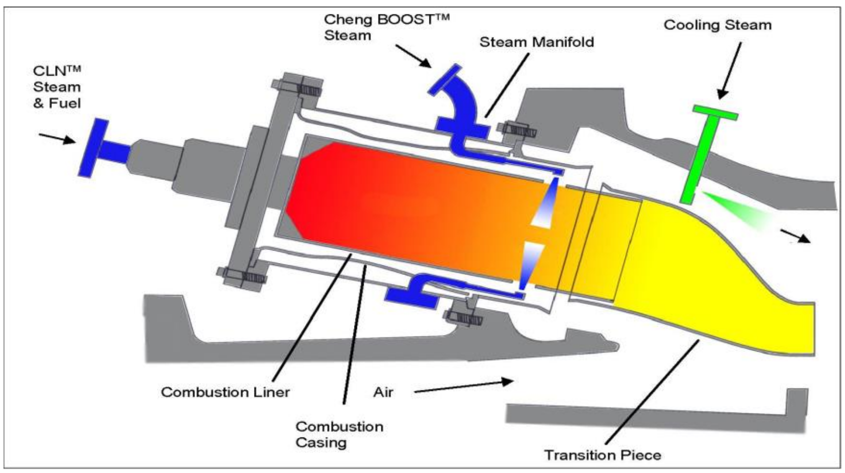
Combustion System	Frame Type	Potential NOx Level
DLN1	GE 3/5/6B/7/9E	9-25 ppmv
DLN1	GE 6B/7E/9E	3-5 ppmv
DLN2.6	GE 6F/7F	9 ppmv
DLN2.6	GE 9F	9 ppmv
Combustion System	**Aero-derivative Type**	**Potential NOx Level**
DLE	GE LMS100 (100 MW)	25 ppmv (gaseous fuel)
DLE	GE LM6000 (40-55 MW)	15-25 ppmv (gaseous fuel) 100 ppmv (liquid fuel)
DLE	GE LM2500 (28 – 34MW)	15-25 ppmv (gaseous fuel) 100 ppmv (liquid fuel)

Cheng Low NOx (CLN)

Cheng Low NOx is an alternative to DLN/DLE. [17-23] In lieu of premixing air to fuel, CLN premixes steam with fuel prior to combustion. The difference in the CLN and the traditional steam injection technology is that CLN can deliver a uniform homogenously mix of steam and fuel to the combustion chamber. A schematic diagram for the CLN is shown in Figure C.2.

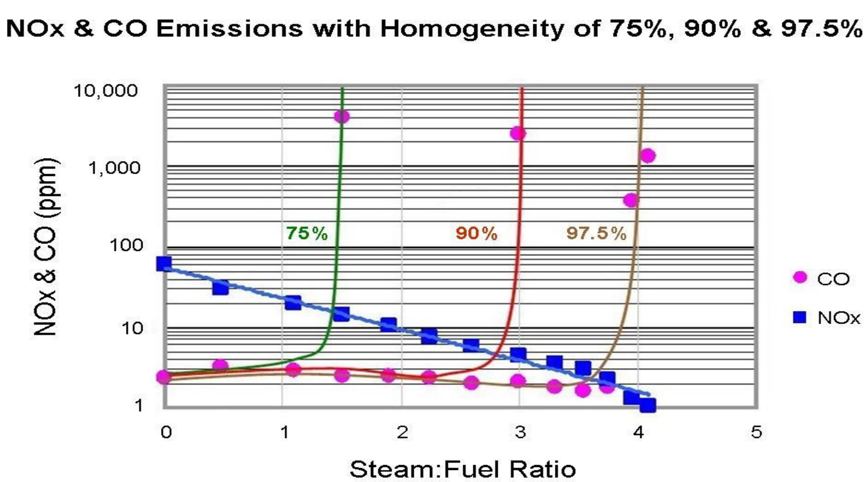
The effect of homogeneity on CO and NOx emissions is shown in Figure C.3. With careful mixing, the steam to fuel ratio can be extended to 4 to 1 without causing any flameout and increasing CO emission. The NOx level can theoretically be lowered to 1 ppmv without the use of SCR. The CO level can be reduced to below 2 ppmv without the use of CO catalyst. [17-20]

The CLN technology was developed by Cheng Power Systems, Inc. It was patented in 2002. Since 2005, the CLN technology has been running continuously on a 6 MW Allison Rolls Royce (RR) KB5S at the Stanford Research Institute (SRI) in Menlo Park. In 2009, it was demonstrated on a GE LM2500 at Calpine Corporation's Agnews Cogeneration Plant. The newest CLN was installed in the GE LM2500PH gas turbine. Table C.3 below shows a list of CLN installation in the past decade.



(Reference 22)

Figure C. 2 - Cheng Low NOx



(Reference 22)

Figure C. 3 - Effect of Homogeneity and Steam to Fuel Ratio in CLN Application

Table C. 3 – Installation of CLN

Engine	Rated Power, MW
RR 501 KH	6.2
RR 501 KB7S	5.2
RR 501 KB5	3.9
RR Avon 1535	15
GE LM2500	22
GE 6B	39.5
LM 6000 PC	43
GE 7EA	85

Figure C.4 below shows some of the test results of CLN. Additional test results can be found in References 18-20. It should be noted that, CLN was put in operation on two GE Frame 6B turbines at a refinery in the SCAQMD. Actual test data at the refinery site in the SCAQMD shows a level of 17.7 ppmv NOx at 15% O2 at the steam to fuel ratio of 1.5.[18-19] Besides lowering NOx and CO emissions, additional benefits that CLN provide are lowering the heat rate and increasing power output.

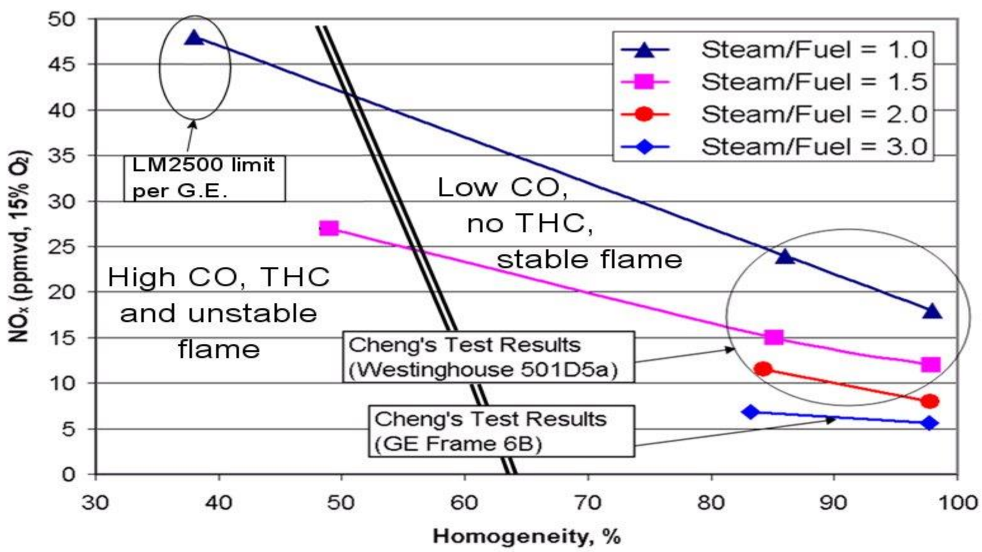


Figure C. 4 - Effect of Homogeneity and Steam to Fuel Ratio on NOx Emissions in CLN Application

In summary, CLN with a steam to fuel ratio of 1.75 to 1 is proven viable to reduce NOx emissions to 9 ppmv or 15 ppmv. SCR can be used in combination with CLN to reach 2 ppmv NOx and CO levels. The current CLN system comes with automatic adjustment software to continuously monitor and optimize the amount of steam to fuel ratio. Cheng Power expected that with a steam to fuel ratio of 3 or 4 to 1, CLN would be able to reach 2 ppmv NOx without the use of SCR.[21-23]

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen through the following reactions. Please refer to Appendix A for further descriptions.

All SCR manufacturers that staff contacted confirm that SCRs can be designed to reduce 95%-98% NOx emissions when used in combination with DLE/DLN, CLN, CO catalysts, ASC, or water/steam injection. It can achieve 2 ppmv NOx while maintaining low ammonia slips of less than 5 ppmv.

Cormetech indicated that they have achieved less than 2 ppmv NOx and 2 ppmv NH_3 in 10 gas turbines; and one of the full scale demonstration project is the 7 MW cogeneration unit located at a refinery in the Los Angeles basin, startup in 2003, achieving <2 ppmv NOx at <0.1 ppmv ammonia slip. [25] BASF advertized that their vanadia/titania catalysts have 99% NOx removal efficiency in the optimum temperature range of 550 – 800 degrees F, and their zeolite catalysts have 99% removal efficiency in the optimum temperature range of 675 – 1075 degrees F, and they also supply ASC that can reduce both ammonia and NOx. [27]

The CO catalysts are used in conjunction with SCR catalysts to concurrently reduce NOx to N2 and oxidize CO and hydrocarbon to CO2 and water. The CO catalysts are typically made of platinum, palladium or rhodium, and have about 90% removal efficiency for CO and 85% to 90% for hydrocarbon or hazardous air pollutants.

Costs and Cost Effectiveness

It has been reported that the costs of SCR catalysts have dropped significantly over time – catalyst innovations have been the principla driver, resulting in a 20 percent reduction in catalyst volume and costs with no change in performance. [10] Staff developed a Cost Curve that plots the PWV of the control devices as a function of gas turbines' maximum rating utilizing the following sets of data:

- Refinery data
- EPA and DOE data
- Data provided by SCR manufacturers and Cheng Low NOx

Staff then used the PWVs from the "Cost Curve" to estimate the costs and cost effectiveness for all 21 turbines/duct burners at the refineries. The details are explained below.

Refinery 1's Cost Information for SCR

In 2011, Refinery 1 received a permit to construct for an 85 MW gas turbine/duct burner. It was planned as the fifth cogeneration unit at this site. SCR and CO catalysts were proposed to control NOx and CO emissions from a DLN combustor. The total installed costs for SCR and CO provided in their application for permit was estimated to be $5.9 million. Staff used a Marshall Index factor of 1.2 to adjust to the current dollars. [7]

This refinery has four existing cogeneration units at the site emitting between 2.52 ppmv to 3.50 ppmv NOx. The refinery reported through a Survey conducted in 2013 that the annual operating costs were $375,000 per year, and catalysts replacement costs were $950,000 every 10 years. [8]

Using Equation 1 below with a Marshall Index adjustment factor of 1.2 to bring the costs to present dollars, staff estimated the PWV for the SCR/CO catalysts were about <u>$15.50 million</u> as shown in Figure C.5.

PWV = Adjustment Factor x (TIC + (15.62 x AC) + (1.14 x CR)) (Equation 1)

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
CR = Catalyst Replacement Costs, $

Refinery 10's Cost Information for SCR

This refinery has a 7 MW cogeneration unit that is using SCR and ASC installed in 2002 to achieve a level of 1.67 ppmv NOx at 15% O2. Through the Survey, the refinery reported total installed costs, annual operating costs, and catalysts replacement costs every 10 years. Using Equation 1 with Marshall Index of 1.4, staff estimated the PWV for SCR/ASC catalysts of about $3.8 million as shown in Figure C.5. [6, 9]

Costs Information from SCR Manufacturers

All SCR manufacturers that staff contacted confirm that it is feasible to achieve 2 ppmv NOx at 5 ppmv ammonia slip for natural gas fueled as well as refinery gas fueled with SCR, CO, or ammonia slip catalysts.

Manufacturer B provided costs to add catalysts and increase the ammonia usage to the SCR of Refinery 1 to achieve 2 ppmv NOx. In this conservative estimate, Manufacturer B assumed that the existing NOx levels were at 10 ppmv. Manufacturer B believed that with the current SCR system at Refinery 1, the refinery could meet 2 ppmv NOx just by adding ammonia. [5]

Additional catalysts = $234,000 ($250 per cubic foot)
Additional ammonia = $11,000 based on $900 per ton ammonia

Manufacturer A provided several sets of cost information for 1) conventional SCRs and for 2) an advanced SCR with Ammonia Slip catalysts for 83 MW and 7 MW cogeneration units with inlet NOx concentrations at 35 ppmv and 50 ppmv to get to 2 ppmv and 5 ppmv outlet NOx concentrations. The costs are summarized in Table C.4 below: [4]

The SCR, CO and ASC have replacement frequency of 10 years. Manufacturer B assumed that the existing ammonia storage tanks and injection systems can be used. Associated equipment such as pump, control valve and vaporizer capacity may increase and not included in the costs. Installation and duct modifications were not included in the costs. Staff used a multiplier factor of 1.6 to add the costs of modification and installation based on Refinery 10 data. Assuming the entire existing SCR and CO catalysts were replaced with SCR and ammonia slip catalysts and using the costs provided by Manufacturer B, staff estimated the SCR/ASC's PWVs would be approximately of $19 million for the 83 MW turbine and $2 million for the 7 MW turbine as shown in Figure C.5.

SCR Costs Information in Literature

Reference 2 contains extensive cost information for SCR catalysts to achieve 80% - 90% reduction from various inlet concentrations to 9 ppmv NOx outlet concentration. The gas turbines in the SCAQMD currently have inlet NOx concentrations in the range of 6 to 2.5 ppmv. An incremental reduction of 80% - 90% is needed to reach 2 ppmv NOx. Thus staff assumed that the entire SCR costs in Reference 2 can be used to estimate the "incremental" costs for the SCRs at the refineries to reach 2 ppmv. The estimated PWVs based on Reference 2 are $4.13 million for SCR of 7 MW turbine, and $22.44 million for SCR of 83 MW turbine as shown in Figure C.5.

Reference 3 contains the total installed costs and annual operating costs for conventional SCR to reach 79% NOx removal efficiency for a 4.2 MW, 23 MW and 161 MW turbines. Staff assumed that these costs can be used to reflect the "incremental" costs for the scenarios in the SCAQMD. From there, staff estimated the incremental PWVs for SCRs would be $4 million for 4.2 MW gas turbine, $11 million for 23 MW gas turbines, and $41 million for 161 MW gas turbines.

Table C. 4 – Costs of SCR and ASC for 83 MW and 7 MW Cogeneration Units at Various Inlet and Outlet NOx Concentrations

Engine	Rated Power 83 MW	Rated Power 83 MW	Rated Power 83 MW	Rated Power 7 MW
Exhaust Flow, lb/hr	2,653,000	2,653,000	2,653,000	140,000
Exhaust Temp, F	625	625	625	625
SCR + CO Catalysts				
NOx in, ppmv	35	50	35	50
NOx out, ppmv	2	2	8 (note)	2
CO Conversion, %	67	67	67	90
NH3 Slip, ppmv	5	5	5	5
Costs, $	1,333,000	1,380,000	1,050,000	$75,000
SCR + Ammonia Slip Catalysts				
NOx in, ppmv	35	50	35	50
NOx out, ppmv	2	2	8	2
CO Conversion, %	92	92	67	92
NH3 Slip, ppmv	5	5	5	5
Costs	$986,000	$1,100,000	$650,000	$60,000

Note: 8 ppmv NOx is the existing permit condition of Refinery 1 cogeneration.

Costs for Cheng Low NOx

Cheng Power Systems provided the following information on costs for CLN to meet 2 ppmv NOx. [20-21] In a presentation to the SCAQMD, Cheng compared the costs to operate a simple cycle 85 MW gas turbine with a Cheng cycle gas turbine to show that within a year of operation, the CLN would generate $9 million savings by reducing heat rate and increasing power, and that savings would offset the $5.5 million installation costs for the CLN. [21] The costs for Cheng Low NOx are listed in Tables C.5 and C.6.

Table C. 5 - Projected Income Gain Due to Power Increase for Cheng Low NOx for Various Types of Gas Turbines

Engine	Power (MW)	Percent Power Increase
RR 501 KB series	5.2	20%
RR Avon 1535	15	20%
GE LM2500	22	20%
GE 6B	39.5	20%
LM 6000 PC	43	16%
GE 7EA	85	20%

Note: For GE 6B, the increase in power during summer was from 34 MW to 42MW. The limit was contractual rather than mechanical.

Table C. 6 - Equipment and Installation Costs for Cheng Low NOx for Various Types of Gas Turbines

Engine	Power (MW)	Hardware	Installation/Software	Total
RR 501 KB series	5.2	$250,000	$125,000	$375,000
RR Avon 1535	15	$500,000	$350,000	$850,000
GE LM2500	22	$950,000	$650,000	$1,600,000
GE 6B	39.5	$1,700,000	$700,000	$2,400,000
LM 6000 PC	43	$1,800,000	$700,000	$2,500,000
GE 7EA	85	$3,000,000	$2,500,000	$5,500,000

Note: The above price assumes a CHP or Combined Cycle Plant with steam heat recovery system available. The extra costs of engine refurbishment or upgrade is to be determined based on a case by case basis and is not included in the above list.

Present Worth Values and Cost Effectiveness

As shown in Figure C.5, staff constructed a curve showing the PWVs for the control devices as a function of turbine MW rating using the PWVs for SCRs derived above. Staff then estimated the PWVs for all gas turbines/duct burners to achieve 2 ppmv NOx with SCR/CO catalysts or SCR/Ammonia slip catalysts. See Table C.7. The PWVs with CLN/SCRs could be less if the savings resulting from increasing power would offset the CLN costs.

The Incremental Cost Effectiveness values were estimated as follows based on the Discounted Cash Flow (DCF) method. A multiplication factor of 1.67 (to account for 25 years life of the SCR/CO/ASC system with frequency of replacement every 10 years) was used to convert the cost effectiveness estimated using DCF method to the Levelized Cash Flow (LCF) method:

CE = PWV / (ER x 365 days x 25 years)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

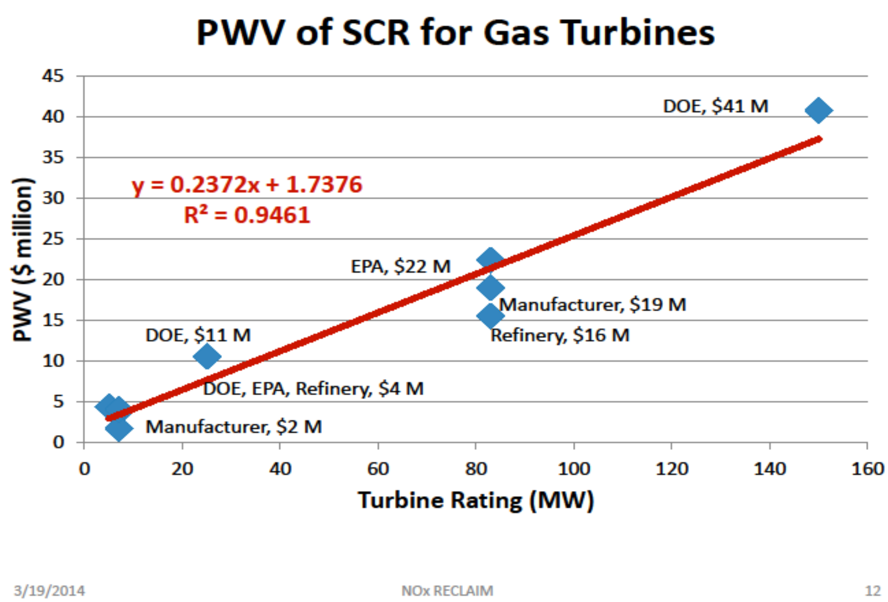


Figure C. 5 - Present Worth Values for Gas Turbines

Table C. 7 – Present Worth Values and Cost Effectiveness for Gas Turbines (December 2014)

No of Units	Rating (MW)	Current NOx Level (ppmv)	Incremental Emission Reduction per Unit from 2005 BARCT (tpd)	SCAQMD's Estimate PWV per Unit ($M)	Incremental Cost Effectiveness ($/ton)
1	59	5.7	0.21	15.7 (new SCR)	8,210
3	46	3-4	0.31	12.6 (new SCR)	4,472
2	30	6	0.20	8.9 (new SCR)	4,851
1	23	5.7	0.14	7.2 (new SCR)	5,631
4	83	2.5-3.5	0.60	4.8 (add catalysts)	870
Total for all units			**4.14**	**97.68**	

It should be noted that the cost estimates in Table C.7 above are very conservative for several refineries as discussed below:

- Refinery 5's gas turbines A, B, and C currently emit 3.5 - 4.5 ppmv NOx at 15% O_2. Refinery 5 recently changed the catalysts used in Turbine A and Turbine B from Hitachi to Cormetech, and reduced the catalyst's volume from 2700 cubic feet to 667 cubic feet. The catalyst's volume of Turbine C is 950 cubic feet. The new Turbine D at Refinery 5 uses only 300 cubic feet of Cormetech catalysts to reach 2 ppmv NOx. Turbine D has DLN. Turbines A, B has CLN with steam injection at steam to fuel ratio of 1.5. Turbine C has steam injection at a steam to fuel ratio of 1.3. It should be noted that the steam to fuel ratio for Turbines A and B was permitted at 2.1 – 2.6 at the time the application was processed. Refinery 5 has several options to reach 2 ppmv NOx: 1) add additional catalysts or change to more effective catalysts, 2) increase the steam to fuel ratio, or 3) retrofit with CLN or DLN. Increasing the steam to fuel ratio could add more power to the system and return the investments within couple years of operation. [20, 28-29].

- Refinery 7 also changed the catalysts to Haldor Topsoe and Cormetech. With the use of more efficient SCR and ASC and additional ammonia, Refinery 7 may be able to reduce the catalyst volume and NOx emissions from 5 ppmv to 2 ppmv NOx without compromising the ammonia slip. [11, 25, 26, 31]

- Refinery 4's two 30 MW turbines currently use water injection, SCR and CO catalysts to achieve 5-6 ppmv NOx. The turbines have permit conditions limiting them to 96 ppmv NOx and 5 ppmv ammonia slip, and 583 tons per year NOx. Refinery 4 can retrofit the unit with steam injection or CLN technology, increase the power and reduce NOx without compromising the ammonia slip. Alternatively, the refinery may change to more effective SCR catalyst type and use ASC to reduce catalyst volume and increase NOx reduction effectiveness without compromising the ammonia slip. [11, 20, 25, 26]

- Refinery 10's gas turbine/duct burner is already at levels below 2 ppmv, thus no incremental costs were estimated for this refinery.

In conclusion, staff proposes to set a new BARCT level of 2 ppmv NOx for refinery gas turbines, aero-derivative as well as frame turbines, because NOx control technologies such as DLE/DLN, CLN, SCR with CO catalysts, SCR with Ammonia Slip Catalysts are commercially available and can be used together to achieve 2 ppmv NOx in a cost-effective manner. A level of 2 ppmv NOx is achieved-in-practice for an aero-derivative 7 MW gas turbine/duct burner using SCR and ammonia slip catalysts. Two 46MW and 83 MW frame cogeneration units with SCR and CO catalysts were given permit to constructs since 2011 with permit conditions limiting to 2 ppmv NOx, 2 ppmv CO and 5 ppmv ammonia slip.

Consultant's Estimates for SCRs

The consultant NEC was in agreement with staff's proposal of 2 ppmv BARCT level for gas turbines using refinery gas. Their estimates for adding catalysts to the existing SCRs of the gas turbines to achieve 2 ppmv NOx are shown in Table C.8 in comparison to staff's estimates: [33]

Table C. 8 - Comparison of Staff's and NEC's Estimates for Gas Turbines

No of Units	Rating (MW)	Current NOx Level (ppmv)	Incremental Emission Reduction per Unit from 2005 BARCT (tpd)	SCAQMD's Estimate PWV per Unit ($M)	NEC's Estimate PWV per Unit ($M)
1	59	5.7	0.21	15.7 (new SCR)	5.1 (add catalysts)
3	46	3-4	0.31	12.6 (new SCR)	4.0 (add catalysts)
2	30	6	0.20	8.9 (new SCR)	2.6 (add catalysts)
1	23	5.7	0.14	7.2 (new SCR)	2.0 (add catalysts)
4	83	2.5-3.5	0.60	4.8 (add catalysts)	7.1 (add catalysts)
Total for all units			**4.14**	**97.68**	**52.7**

Staff's Recommendation

Staff recommends to set a new BARCT level of 2 ppmv NOx for refinery gas turbines because NOx control technologies such as DLE/DLN, CLN, SCR with CO catalysts, SCR with Ammonia Slip Catalysts are commercially available and can de used together to achieve 2 ppmv NOx in a cost-effective manner. A level of 2 ppmv NOx is achieved-in-practice for a turbine/duct burner 1,7 MW cogeneration unit using SCR and ammonia slip catalysts. An 83 MW cogeneration with SCR and CO catalysts was given a permit to construct since 2012 with a permit condition of 2 ppmv NOx.

In summary:

Incremental Emission Reductions beyond 2005 BARCT level = <u>4.14 tons per day</u>
Total Incremental Costs = <u>$52.7 (consultant's estimates) - 97.68 M (staff's estimates)</u>
Average Incremental Cost Effectiveness = <u>1,452 – 2,692 $/ton (DCF) and 2K – 4.5K $/ton LCF)</u>

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Appendix D - Coke Calciner

Process Description

There is only 1 coke calciner in the SCAQMD. Engineering of the coke facility began in 1978 by Martin-Marietta. Initial production of calcined coke occurred in February 1983. The company was purchased by BP Products Company in 1985. BP produces calcined coke in two locations in the United States: Wilmington California and Cherry Point Washington, and two locations in Germany: Gelsenkirchen and Lingen. The company was purchased by Tesoro in 2013.

Coke calcining is a process to improve the quality and value of "green coke" produced at a delayed coker in a refinery. The green feed, produced by nearby Carson Refinery, is screened and transported to the coke calcining facility by truck, where it is stored under cover in a coke storage barn. The screened and dried green coke is introduced into the high end of the rotary kiln, 3 feet diameter x 270 ft long, is tumbled by rotation, moves down the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or oil. The kiln temperatures are in a range of 2000 – 2500 degrees Fahrenheit. The green coke is retained in the kiln for approximately one hour to drive off the moisture, impurities, and hydrocarbon. After discharging from the kiln, the calcined coke drops into a cooling chamber, where it is quenched with water, treated with dedusting agents for dust control, carried by conveyors to storage tanks, and later are transported by trucks to the Port of Long Beach for export, or is loaded into railcars for shipments to domestic customers. A simplified process diagram of the calcining process is shown in Figure D.1.

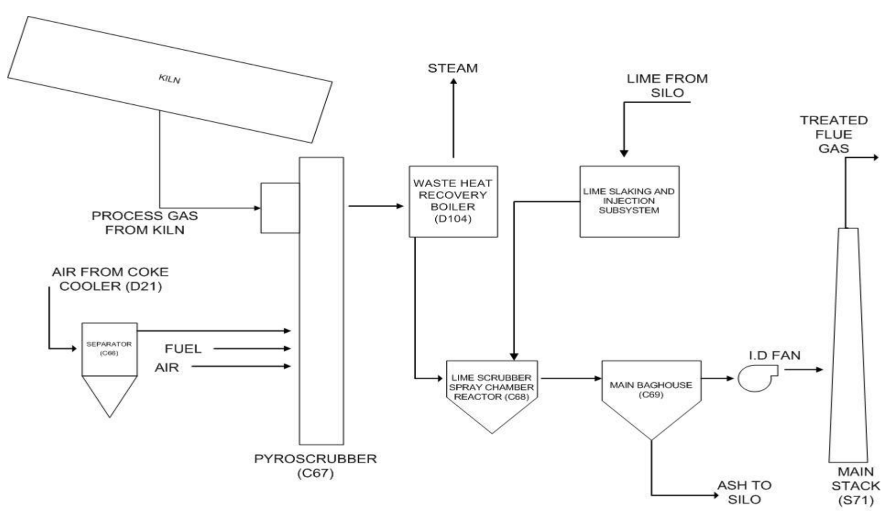

FIGURE 1: SIMPLIFIED PROCESS FLOW DIAGRAM

Figure D. 1 - Coke Calciner Process

The coke calciner produces approximately 400,000 short tons per year of calcined products. The Wilmington coke calciner is limited to a maximum processing rate of 1,980 tons green coke per day, and is increasing to 2,400 tons of green coke per day. This plant is a global supplier of calcined coke to the aluminum industry, and fuel grade coke to the fuel, cement, steel, calciner, and specialty chemicals businesses. [1]

Emission Inventory

The 2011 NOx emissions from the coke calciner and current NOx outlet concentration are shown in Table D.1. The total 2011 emissions are 0.55 tons per day. The NOx outlet concentration at 65 ppmv is higher than the 2005 BARCT level set at 30 ppmv (0.036 lb/mmbtu).

Table D. 1 - 2011 Emissions for Coke Calciner

Fac ID	Device ID	Device	2011 Emissions (lbs)	Current NOx at 3% O_2 (ppmv)
2	C67	Afterburner	390,625	65
2	D20	Rotary Kiln	11,403	65
		Total (tpd)	**0.55**	

Control Technology

The commercially available control technologies for NOx emissions from the coke calciner are LoTOx and UltraCat, two commercially available multi-pollutant control technologies for low temperature removal of NOx.

LoTOx™ Application

LoTOx™ stands for "Low Temperature Oxidation" process where ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds. Refer to Appendix A for further details. It should be noted that LoTOx is a low temperature operating system, meaning that it does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases. In addition, LoTOx can be used with a wet (or semi-wet) scrubber, and together the system becomes a multi-component air pollution control system that can reduce NOx, SOx and PM concurrently. There are more than 50+ applications engineered by Linde LLC. since 1997, and more than two dozen applications with EDV™ scrubbers engineered by BELCO Dupont since 2007. [2-3] Refer to Table A.2 of Appendix A for a list of LoTOx applications in FCCUs, boilers, furnaces, and other combustion equipment. Applications in gas-fired and high sulfur coal-fired units met 2-5 ppmv.

Current installations in refineries met 8-10 ppmv. The technology can be applied to coke calciner, and manufacturer confirmed that LoTOx can be designed to achieve 2 ppmv NOx from current inlet concentrations of the coke calciner.

In addition, it should also be noted that during the rule development for SOx RECLAIM amendments in 2010, the SCAQMD has set a BARCT level of 10 ppmv SOx for the coke calciner. It was determined that wet scrubbers engineered by BELCO, Tri-Mer and MECS were all feasible and cost effective. LoTOx application can be integrated in any of these scrubbers to reduce NOx, SOx, PM and other toxic pollutants. The footprint needed for scrubbers and associated equipment was estimated to be about 30 ft x 40 ft. The facility has not yet installed any scrubber since the adoption of SOx RECLAIM amendments in 2010.

UltraCat™ Application

UltraCat is also a multi-component air pollution control technology developed by Tri-Mer. UltraCat catalyst filters are composed of fibrous ceramic materials embedded with proprietary catalysts that can remove NOx, SO_2, PM, HCl, Dioxins, and HAPs. The optimal operating temperatures are approximately 350 to 750 degrees F. Aqueous ammonia injected upstream of the catalytic filters is used to remove NOx. NOx removal efficiency is about 95%. Dry sorbent such as hydrated lime, sodium bicarbonate or trona injected upstream of the catalytic filters is used to remove SO2, HCl, and other acid gases with a removal efficiency of 90% - 98%. Particulate control to a level of 0.001 grains/dcsf and mercury control are also possible. UltraCat filters are arranged in a baghouse configuration with low pressure drop, about 5" water column, and it has a reverse pulse-jet cleaning action meaning that the filters are back flushed with air and inert gas to dislodge the particulate deposited on the outside of the filter tubes. Catalytic filter tubes are replaced every 5 to 10 years. The UltraCat catalytic filtering system is depicted in Figure D.2.

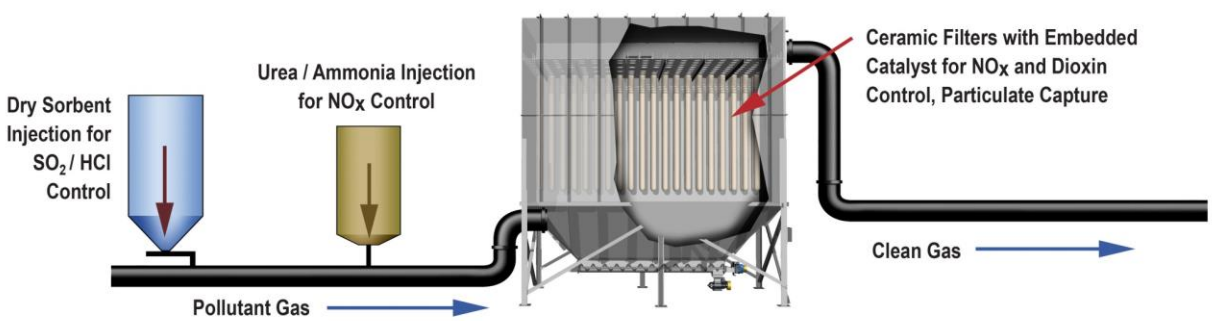

Figure D. 2 - Ultra-Cat Filters

Costs and Cost Effectiveness

LoTOx^{TM} Application

Table D.2 contains costs information provided by LoTOx manufacturer.[4] Staff estimated the Present Worth Value (PWV) using the equations below for the Discounted Cash Flow (DCF) method assuming 4% interest rate and 25-years life for the control device. Staff applied a contingency factor of 1.5 to account for any additional costs that might occur. Incremental cost effectiveness was estimated as follows for the DCF method:

PWV = 1.5 x (TIC + (15.62 x AC)) (Equation 1)
CE = PWV / (ER x 365 days x 25 years) (Equation 2)

Where:
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
ER = Incremental Emission Reductions

In December 2014, the PWV and CE for LoTOx application were estimated to be $22 million and $10,347 per ton NOx reduced per DCF method as shown in Table D.3. The CE would be $17,073 per ton NOx reduced per Levelized Cash Flow (LCF) method.

UltraCat^{TM} Application

Table D.2 contains costs information provided by UltraCat manufacturer.[6] In December 2014, staff estimated the TIC based on the OAQPS EPA Guidelines, i.e. TIC = 1.86 * Equipment Costs. Staff also applied a contingency factor of 1.5 to account for any additional costs that might occur. The PWV assuming 4% interest rate and 25-years life for the control device and the CE were estimated using Equations 1 and 2 shown above. The incremental emission reductions for Ultra-Cat system were estimated to be 0.23 tpd NOx and 0.28 tpd SOx

In December 2014, the PWV and incremental cost effectiveness for UltraCat application were estimated to be $61 million and $13,071 per ton NOx and SOx reduced estimated using DCF method as shown in Table D.3. The incremental cost effectiveness would be $13 K per ton NOx and SOx reduced estimated with the DCF method.

Consultant's Analysis for LoTOx and Staff's Revised Estimates for LoTOx and UltraCat

The consultant NEC suggested that a BARCT level of 2 ppmv was not feasible, and recommended 5 ppmv – 10 ppmv BARCT level for the coke calciner. NEC also suggested that a factor of 1.86 to estimate TIC and an adjustment of 1.5 were not conservative enough since space was extremely challenging at the coke calciner facility. A factor of 4.5 – 4.6 was more reasonable. Staff concurred with NEC recommendation and re-estimated the PWVs for the Ultra-Cat application as shown in Table D.4.

Staff's Recommendation

Staff recommends to set a BARCT level of 10 ppmv NOx for coke calciner because NOx control technologies such as LoTOx and UltraCat are commercially available to achieve this level in a cost-effective manner.

2014 BARCT NOx = (0.08 tpd)(2000 lb/ton)(365 days/yr)/(81,471 ton coke/yr) = <u>0.8 lb/ton coke</u>
Total incremental emission reductions beyond 2005 BARCT = <u>0.17 ton per day</u>
Total incremental costs = <u>$39.5 million - $91 million</u>
Total incremental cost effectiveness = <u>$22 - $35 K per ton</u>

Table D. 2 – Costs of LoTOx and UltraCat for Coke Calciner (December 2014)

2011 NOx emissions	0.55 tons per day NOx
Current NOx concentration	64.95 ppmv NOx
2005 NOx BARCT level	30 ppmv NOx
2010 SOx BARCT level	10 ppmv SOx
2014 BARCT proposed level	2 ppmv NOx
2011 NOx emissions at 30 ppmv BARCT	0.25 tpd
2011 NOx emissions at 2 ppmv BARCT	0.02 tpd
Incremental NOx emission reductions	0.23 tpd
Flue Gas Temp	450 degrees F
Flue Gas Flow	6,806,770 dscfh (113,446 scfm)
Stack Oxygen	5%
Stack Moisture	29.8%
Coke Burned	81,471 tons per year
LoTOx Application for 2 ppmv NOx (97% control)	
Total Installed Costs	$6,250,000
Operating Costs	$544,300 per year
LoTOx Application for 5 ppmv NOx (92% control)	
Total Installed Costs	$6,200,000
Operating Costs	$516,800 per year
Ultra Cat Application for 2 ppmv NOx (97% control)	
Capital Costs of Emission Control	$7,531,774
Operating Costs – Utility, Catalysts, Labor, Maintenance	$1,721,490 per year
Filters replacement frequency	5 years at $215,600 per year

Table D. 3 - Cost and Cost Effectiveness Estimates for Coke Calciner (December 2014)

	Emission Reductions	PWV ($M)	Incremental CE ($/ton)
LoTOx	0.23 tpd NOx	22.13	10,374
UltraCat	0.23 tpd NOx + 0.28 tpd SOx	61.35	13,071

Table D. 4 – Revised Cost and Cost Effectiveness Estimates for Coke Calciner (March 2015)

	Staff's Estimates Using Factor of 4.5 BELCO	Tri-Mer	NEC's Estimates
BARCT Level	10 ppmv	92% control	10 ppmv
Incremental Reductions (tpd)	0.17	0.17+0.28=0.45	0.17
PWV ± 50% ($M)	54.29	91.17	39.50
Cost Effectiveness ($/ton)	$35K/ton	$22K/ton	$25K/ton

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Appendix E - Sulfur Recovery Units/Tail Gas Incinerators

Process Description

A sulfur recovery unit and tail gas treatment unit (SRU/TGTU) at the refineries include a Claus unit followed by an amine absorption unit to recover the sulfur from various gaseous streams at the refineries. 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. The tail gas is then vented to a thermal (or catalytic) oxidizer (incinerator) where the residual H_2S in the tail gas is oxidized to SO_2 before emitting to the atmosphere. The refinery SRU/TGTUs including their incinerators are classified as major sources of NOx and SOx.

It should be noted that since the interception of the RECLAIM in 1993 until 2010, the SCAQMD did not set any Best Available Retrofit Control Technology (BARCT) standards for the SRU/TGTUs and incinerators. In 2010, the SCAQMD set a new BARCT standard for SOx at 5 ppmv, 0% O2. At that time, it was determined that Refineries 1, 5, and 6 could retrofit their SRU/TGTUs cost-effectively with wet gas scrubbers (WGS) to further reduce SOx emissions. The construction time was estimated to be about 3 years. [1] As of today, Refineries 1, 5 and 6 did not retrofit any of their existing SRU/TGTUs, instead they selected to purchase RECLAIM Trading Credits or reduce SOx elsewhere in the refinery to comply with their facility emission caps. In 2011, Refinery 5 installed a new SRU/TGTU at their refinery. Since the new SRU/TGTU was subject to Best Available Control Technology (BACT), Refinery 5 was required to install and operate with a WGS, and the BACT evaluation for NOx is still under evaluation.

Emission Inventory

The 2011 NOx emissions from the SRU/TGTUs and incinerators in the SCAQMD and their current NOx outlet concentration are shown in Table E.1. The total 2011 emissions are 0.43 tons per day. The NOx concentrations at the stack vary widely from 6 ppmv to 70 ppmv. It should be noted that their SOx emissions also vary widely from 20 ppmv to 150 ppmv.

Control Technology

Commercially available control technologies for NOx emissions are Selective Catalytic Reduction (SCR) and LoTOx. KnowNOx has been installed at two locations in the U.S. however has not yet been tested in any refinery applications as of today. While SCR is considered as a high temperature NOx reduction technology, LoTOx and KnowNOx are known for low temperature multi-pollutant control systems since they can be integrally connected with a WGS to reduce NOx, SOx, PM, VOC, HAPs, and other toxic compounds.

Table E. 1 - 2011 Emissions for SRU/TG Incinerators

Unit	Fac ID	Device ID	Device	2011 Emissions (lbs)	Existing NOx @ 3% O2
1	9	1260	INCINERATOR	7,696	66.81
2	6	952	INCINERATOR	41,066	6.57
3	5	911	INCINERATOR	28,379	29.00
4	5	913	HEATER	12,087	29.00
5	5	927	INCINERATOR	14,276	27.00
6	5	929	HEATER	6,080	29.00
7	5	955	INCINERATOR	40,313	29.83
8	5	957	HEATER	13,035	29.83
9	1	910	INCINERATOR	42,273	28.07
10	1	2413	INCINERATOR	22,337	18.33
11	10	175	INCINERATOR	5,674	45.89
12	3	54	INCINERATOR	13,115	55.00
13	3	56	INCINERATOR	4,931	55.00
14	7	436	INCINERATOR	8,030	18.68
15	7	456	INCINERATOR	7,025	31.85
16	8	294	thermal INCINERATOR	49,563	32.00
17	8	292	catalytic INCINERATOR	1,010	not reported
			Total (tpd)	**0.43**	

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen. Refere to Appendix A for further details

For the past two decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available. The advanced SCRs can be designed to reduce 95%-98% NOx emissions from the SRU/TGTUs and incinerators and achieve 2 ppmv NOx while maintaining a low ammonia slip of less than 5 ppmv. [3-14]

LoTOx^{TM} Application

LoTOx^{TM} stands for "Low Temperature Oxidation" process where ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds which can be subsequently removed by absorption in caustic solution, lime or limestone. Please refer to Appendix A for details. As of today, there are more than 50+ LoTOx applications engineered by Linde LLC., and two dozen applications engineered by BELCO of Dupont for refinery FCCU applications.[15, 22] While BELCO's expertise is in the refinery FCCUs, its sister company MECS has engineered more than two dozen DynaWave scrubbers specifically designed for refinery SRU/TGTUs. Figure E.1 shows a schematic for a DynaWave scrubber. Figure E-2 contains a schematic for LoTOx process incorporated into the DynaWave scrubber.

Currently, LoTOx applications in the FCCU applications have achieved 8 ppmv - 10 ppmv NOx, and 2 ppmv – 5 ppmv NOx in the gas-fired and high sulfur coal-fired units. [15, 22] LoTOx technology can be incorporated to the refinery SRU/TGTUs' incinerators and designed to achieve a level of 2 ppmv NOx outlet concentrations.[24]

Table E.3 has a list of the DynaWave installations in the U.S. [25] This is not an inclusive list. Besides refinery SRU/TGTUs, DynaWave scrubbers are used in numerous other industrial applications such as sulfuric acid plants, coke calciner, metallurgical plants, secondary aluminum or copper smelters, coal fired heaters and boilers, sulfur pits, platimum recovery plants, cement kilns, meat rendering plants, and medical waste incinerators. DynaWave scrubbers have been used in the industries since 1987.

In addition, it should be noted that the SCAQMD set a BARCT standard for SOx at 5 ppmv, 0% O_2, annual average in 2010. In 2011, Refinery 5 installed a new SRU/TGTU with a DynaWave scrubber to meet a short-term BACT standard of 10 ppmv. The most recent source test shows that the DynaWave scrubber meets <1 ppmv SOx, corrected to 0% O_2. Thus, reducing NOx and SOx to a 1-digit level concurrently is feasible and cost-effective, and it can be done with DynaWave and LoTOx combination application.

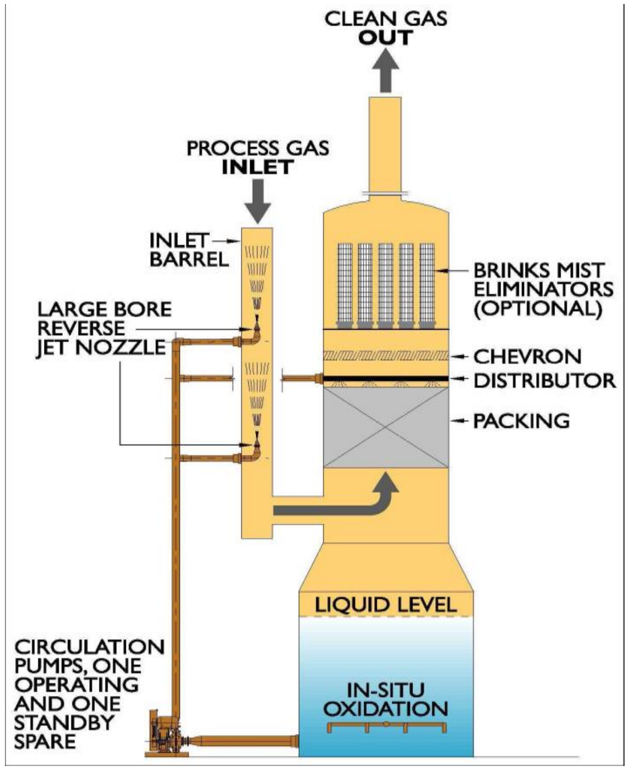

Figure E. 1 - DynaWave Scrubber

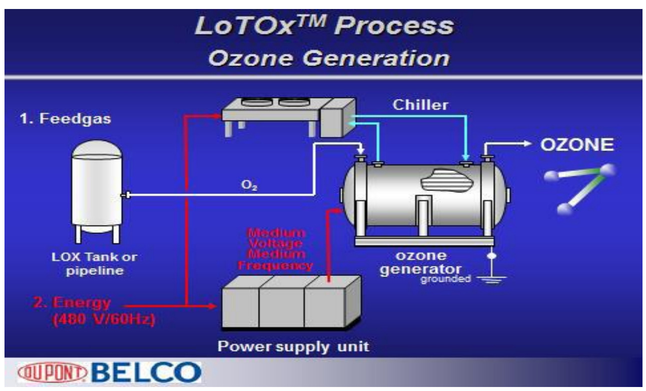

Figure E. 2 - Ozone Generation Process

Table E. 2 - List of DynaWave Scrubber Installations for SR/TGTUs

Company/Location	StartUp Date	Exit Gas ACFM	Application
KiOR	2012	82,135	BioRefinery FCC Off Gas
Mississippi			Quench, SO_2 and Particulate
Calumet	2010	15,545	40 LTPD SRU Tail Gas Clean Up
Louisiana			SO_2 removal with NaOH
Chevron	2013	27,800	SRU SCOT Tail Gas Clean Up
California			SO_2 removal with NaOH
Sinclair	2009	59,603	FCC Off Gas
Oklahoma			Quench, SO_2 and Particulate
Wyoming Refining	2011	57,746	FCC Off Gas
Wyoming			Quench, SO_2 and Particulate
Pasadena Refining	2008	2,200	S Zorb Off Gas
Texas			SO_2 removal with NaOH
ConocoPhillips	2006	6,700	S Zorb Off Gas
Illinois			PM and SO2 removal with NaOH
Sinclair	2006	9,000	25 LTPD SRU Tail Gas Clean Up
Oklahoma			SO_2 removal with NaOH
Marathon Ashland	2008	10,100	33 LTPD SRU Tail Gas Clean Up
Texas			SO_2 removal with NaOH
Sinclair	2005	12,830	47.5 LTPD SRU Tail Gas Clean Up
Wyoming			SO_2 removal with NaOH
Sinclair	2005	5,700	18 LTPD SRU Tail Gas Clean Up
Wyoming			SO_2 removal with NaOH
ConocoPhillips	2005	2,000	S Zorb Off Gas
Louisiana			SO_2 removal with NaOH
Navajo	2003	100,000	FCC off gas NaOH scrubber for SO_2 and PM
New Mexico			
ConocoPhillips	2003	3,300	S Zorb Offgas
Washington			SO_2 removal using NaOH
Unocal Refining	1993	17,300	Spent sulfuric acid plant
California			
Hess Oil St. Croix	1993	9,400	Spent sulfuric acid plant
Virgin Islands			Gas cleaning for new plant
Sun Refining	1991	2,000	H2S and sour water incinerator
Pennsylvania			Particulate and SO3 removal
BP	1990	130,000	Coke calciner
Washington			PM/SO2 removal with soda ash

KnowNOx™ Application

In lieu of using ozone to convert NO and NO_2 to N_2O_5 and HNO_3, the KnowNOx technology uses chlorine dioxide ClO_2. The conversion reactions (Reactions 12 and 13) are in the gas phase, which can occur much faster than the liquid phase reactions with ozone (Reactions 5 and 6). It takes less than 0.5 seconds to achieve 99.8% or more conversion. The reactions require a smaller vessel in relative to the LoTOx reaction chamber. In addition, the KnowNOx process can simultaneously reduce NOx, SO_2, PM and other contaminants.[26-28]

$5\ NO + 2\ ClO_2 + H_2O \rightarrow 5\ NO_2 + 2\ HCl$ (Reaction 12 - Gas Phase)
$5\ NO_2 + ClO_2 + 3\ H_2O \rightarrow 5\ HNO_3 + 2\ HCl$ (Reaction 13 – Gas Phase)
$5\ SO_2 + 2\ ClO_2 + 6\ H_2O \rightarrow 5\ H_2SO_4 + 2\ HCl$ (Reaction 10)

The conceptual layout for the KnowNOx process is shown in Figure E.3. It includes a three-stages scrubbing system: SO_2 is scrubbed at the 1st stage with a DynaWave scrubber, ClO_2 injected to the 2nd stage converts NO and NO_2 to HNO_3 and other soluble salts, and H_2S generated in the 2nd stage is converted to soluble salts in the 3rd stage. The KnowNOx technology is a feasible concept. It has been installed at two locations in the U.S. however has not yet been tested in any refinery applications as of today, and may not yet been proven at full scale operations.

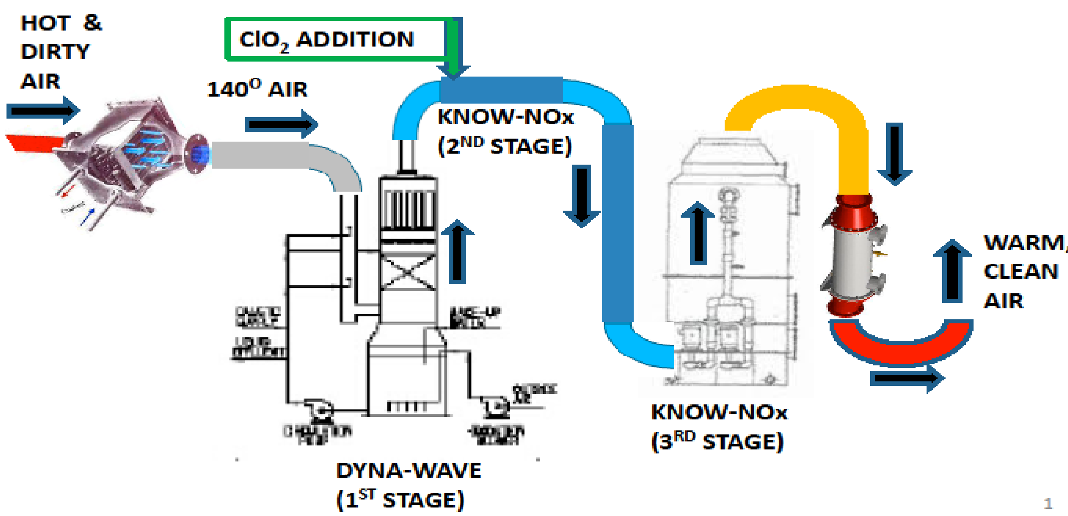

Figure E. 3 – KnowNOx Process

Costs and Cost Effectiveness

Some process conditions of the SRU/TGTUs at the refineries in the SCAQMD and the outlet NOx concentrations are listed in Table E.3. To gather the control equipment cost information from the manufacturers, staff provided the manufacturers with the information for the three scenarios, as shown in Table E.4 reflecting the units with highest emissions and flue gas flow rates from the 17 SRU/TGTUs/incinerators in the SCAQMD.

Table E. 3 - Process Information and NOx Emissions for SRU/TG Incinerators in SCAQMD

Unit	Fac ID	Device ID	Device	Max Rating (mmbtu/hr)	Flue Gas Flow rate (dscfm)	Flue Gas Temp (degree F)	Existing NOx (ppmv)
1	9	1260	INCINERATOR	36			66.81
2	6	952	INCINERATOR	100	34,640	1,080	6.57
3	5	911	INCINERATOR	30	12,500	515	29.00
4	5	913	HEATER	25	12,500	515	29.00
5	5	927	INCINERATOR	30	12,500	570	27.00
6	5	929	HEATER	25	12,500	570	29.00
7	5	955	INCINERATOR	58	14,500	520	29.83
8	5	957	HEATER	41	14,500	520	29.83
9	1	910	INCINERATOR	45	32,167	1,260	28.07
10	1	2413	INCINERATOR	40	27,167	1,292	18.33
11	10	175	INCINERATOR	10			45.89
12	3	54	INCINERATOR	52			55.00
13	3	56	INCINERATOR	45			55.00
14	7	436	INCINERATOR	20			18.68
15	7	456	INCINERATOR	20			31.85
16	8	294	thermal INCINERATOR	28	23,284		32.00
17	8	292	catalytic INCINERATOR	15			

Staff estimated the PWV for the control system using Equation 1 below assuming 4% interest rate and a 25-years life for the control device:

PWV = (Contingency Factor) x (TIC + (15.62 x AC) + (2.52 x CR)) (Equation 1)

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
CR = Catalyst Replacement every 5 years
Contingency factor = 1.5

Table E. 4 – NOx and SOx Performance of SRU/TG Applications in SCAQMD

	Scenario 1 Refinery 6	Scenario 2 Refinery 1	Scenario 3 Refinery 5
Incinerator Rating	100 mmbtu/hr	45 mmbtu/hr	100 mmbtu/hr (note)
Average flue gas flow rate	36,000 dscfm	32,000 dscfm	14,500 dscfm
Temperature	1100 degrees F	1200 degrees F	520 degrees F
O2 %	2.5%	6% - 8%	4%
Current NOx concentration	21 ppmv	28 ppmv	30 ppmv
Current SOx concentration	40 ppmv	75 ppmv	20 ppmv

Note: Incinerator 58 mmbtu/hr and heater 41 mmbtu/hr vented to a common stack

Staff used the factors in the EPA OAQPS Guidelines to estimate the TIC, i.e. TIC = 1.86 x Equip. Costs. A contingency factor of 1.5 was added to the TIC and AC to account for operational uncertainties. Incremental Cost Effectiveness (CE) was estimated as shown in Equation 2 using the Discounted Cash Flow (DCF) method. For comparison, the incremental cost effectiveness would be about 1.65 higher if it was calculated using the Levelized Cash Flow (LCF) method:

CE = PWV / (ER x 365 days x 25 years) (Equation 2)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

Costs for SCRs

Manufacture A's estimates are summarized below: [13]

- It is feasible to achieve 2 ppmv NOx and 5 ppmv ammonia slip,
- All three scenarios would result in about the same costs,
- Costs for SCR catalysts would be about $600,000 and installation costs about $600,000,
- Add costs for heat exchangers in Scenario 1 and 2, and
- Inlet NOx could be higher but would not affect the overall cost estimates.

Manufacturer B's estimates are summarized below: [14]

- It is feasible to achieve 2 ppmv NOx and 5 ppmv ammonia slip,
- SCR costs for Scenario 1 and 2 were estimated to be about $461,000 for SCR at 80% NOx control efficiency. SCR costs for Scenario 3 would be about 10% less than Scenario 1 and 2.
- Costs for a system at 90% control efficiency would be about 5% higher than the costs for a system at 80% control efficiency.

- Costs for a system with 95% control efficiency would be about 10% higher than the costs for a system at 80% control efficiency.
- Estimated costs would not vary with inlet NOx concentration
- SCR footprint and dimension:
  - Catalysts with 1 layer and 1 module for a system with 85% control efficiency. Add 3 in of catalysts for a 95% control efficiency system
  - Add 2 ft in each direction for structural steel, and 6" for insulation
  - SCR overall dimension: 15 ft x 15ft x 15 ft
- Heat exchanger would be required for Scenarios 1 and 2 to lower the temperatures to the optimum temperatures of about 750 degrees F
  - Heat exchanger would cost about $100,000
  - Dimension for a horizontal flow heat exchanger: 6 ft Dia x 6ft - 10 ft L.
- Ammonia usage (19% aqueous ammonia):
  - 11.1 lb/hr for 80% removal, 12.1 lb/hr for 90% control, 12.6 lb/hr for 95% control
  - About $82,000 per year NH_3 costs and $40,000 miscellaneous for a 95% control
  - Dimension of 2000-gallons NH_3 storage tank: 4 ft D x 24 ft L, or 6 ft D x 10 ft L.
  - Ammonia storage tank costs $15,000 (30 days supply)
- Catalyst replacement would be every 5 years. Replacement frequency would depend on actual flue gas constituents and could be guaranteed for a turnaround cycle.

Costs for LoTOx™ Applications

MECS's cost estimates for LoTOx system to reduce NOx emissions are shown in Table E.5. MECS also provided costs for DynaWave and LoTOx in one system to reduce both NOx and SOx emissions as shown in Table E.5. [24]

Costs for KnowNOx™ Applications

Costs provided by KnowNOx for its system to reduce only NOx emissions are shown in Table E.6. KnowNOx also provided costs for DynaWave scrubber in combination with its technology to reduce both NOx and SOx emissions.[29]

In 2014, staff estimated that SCRs, LoTOx and KnowNOx would be cost-effective for 10 SRU/TGTUs (out of 17 units) at Refineries 1, 5, 6 and 8. The PWVs for SCRs, LoTOx and KnowNOx were estimated to be $48.7 M, $68 M and $39 M respectively. The cost effectiveness for the 7 SCRs was estimated to be $15 K per ton NOx reduced (DCF) and $25 K per ton NOx reduced (LCF) as shown in Table E.7.

Table E. 5 – Cost Information Provided by MECS

	Scenario 1		Scenario 2		Scenario 3	
	LoTOx	**Dynawave LoTOx**	**LoTOx**	**Dynawave LoTOx**	**LoTOx**	**Dynawave LoTOx**
Inlet Temp, degrees F	1,100	1,100	1,200	1,200	520	520
Inlet Flow, scfm	38,710	38,710	34,409	34,409	15,761	15,761
Outlet Temp, degrees F	158	158	161	161	139	139
Outlet Flow, scfm	52,782	52,782	48,329	48,329	18,021	18,021
Total Installed Costs, $	5,666,000	8,432,000	5,605.000	8,311,000	4,903,237	6,907,000
Operating Costs, $/yr	89,356	260,600	98,713	276,110	47,000	73,650

Table E. 6 – Cost Information Provided by KnowNOx

	Scenario 1		Scenario 2		Scenario 3	
	KnowNOx	**Dynawave KnowNOx**	**KnowNOx**	**Dynawave KnowNOx**	**KnowNOx**	**Dynawave KnowNOx**
Inlet Flow, scfm	36,000	36,000	32,000	32,000	14,500	14,500
Total Inst Costs, $	1,420,225	4,220,226	1,398,286	4,198,286	1,401,825	3,402,226
Operating Costs, $/yr	108,284	289,936	112,957	295,948	198,729	227,337

Consultant's Analysis for SCRs and Staff's Revised Estimates for SCRs and LoTOx

The consultant NEC confirmed that the 2 ppmv proposed BARCT level is feasible for the refinery SRU/TG incinerators. However, the consultants indicated that the factor of 1.86 from the EPA OAQPS Guidelines was low and suggested staff used a factor of 4.5. NEC also recommended using SCRs with 3 layers of catalysts and 33-ft high, and added the costs of waste heat boilers and new ammonia tanks and associated equipment. A comparison of NEC's and staff's estimates is shown in Table E.7.

Staff review of NEC's analysis is in Appendix H. After extensive discussion, staff used a different approach than NEC to obtain the SCR costs. Staff was in agreement with NEC that the factor of 1.86 based on the EPA OAQPS Guidelines was not conservative for retrofitting applications at the refineries. Thus, staff revised the cost estimates using the factor of 4.5 recommended by NEC. The revised estimates are shown in Table E.8. Per staff revised estimates, there would be about 9 cost effective SRU/TG units with a total incremental emission reductions of 0.32 tpd at PWVs of $82.5 M for SCRs or $105.8 M for LoTOx applications.

Table E. 7 - Comparison of SCR Costs Estimated by Staff and NEC for SRU/TGTUs (December 2014)

	SCAQMD's Estimates for SCRs	NEC's Estimates for SCRs
PWVs for SCRs	$ 48.7 M	$ 96.4 M
Cost Effective Units	10	9
Emission Reductions	0.35 tpd	0.32 tpd
Cost Effectiveness (DCF)	15,233 $/ton	33,014 $/ton

Table E. 8 - Revised Cost and Cost Effectiveness Estimates for SCRs and LoTOx for SRU/TGTUs (March 2015)

Fac ID	Dev	SCR			LoTOx		
		AQMD ($M)	Reductions (tpd)	AQMD CE ($/ton)	AQMD ($M)	Reductions (tpd)	AQMD CE ($/ton)
6	D952	16.2	0.05	33,298	22.7	0.05	46,458
5	911/913	11.3	0.05	23,491	18.9	0.05	39,321
5	927/929	11.3	0.03	46,697	18.9	0.03	78,167*
5	955/957	11.3	0.07	17,818	18.9	0.07	29,826
1	910	17.3	0.06	34,379	22.7	0.06	45,127
1	*2413*	*16.9*	*0.03*	*63,593***	*22.7*	*0.03*	*85,404***
8	294	15.2	0.06	25,805	22.7	0.06	38,490
Total for cost-effective units		**82.5**	**0.32**	**28,270**	**105.8**	**0.29**	**39,963**

*this unit was cost effective using SCR technology thus was included in the revised analysis. ** this unit was not cost effective using either SCR or LoTOx thus was not included in the revised cost analysis.

Staff's Recommendation

Staff recommends to set a new BARCT level of 2 ppmv NOx for SRU/TG incinerators (95% control efficiency) because NOx control technologies such as SCR and LoTOx (or KnowNOx) with DynaWave scrubbers are commercially available and can de designed to achieve 2 ppmv NOx in a cost-effective manner.

In summary:

- Incremental Emission Reductions beyond 2005 BARCT level = 0. 32 tons per day
- No of cost effective units = 9
- Total Incremental Costs = $83 M ± 50% with SCRs - $106 M ±50% with LoTOx application

- Average Incremental Cost Effectiveness (DCF method) = $28K per ton NOx reduced with SCRs - $40K per ton NOx reduced with LoTOx applications
- Average Incremental Cost Effectiveness (LCF method) = $46K per ton NOx reduced with SCRs - $66K per ton NOx reduced with LoTOx applications.

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Appendix F – Review of NEC's Analysis for FCCUs

Staff used two approaches to review NEC's estimates.

Review Using Refinery 1's SCR Costs

Refinery 1 has a SCR to control NOx from their FCCU. The SCR was installed in 2003 with 2 layers of catalysts and 1 spare layer and achieved 2 ppmv NOx. Refinery 1 submitted capital costs and annual operating costs to SCAQMD in response to the SCAQMD's Survey in 2013. The following steps were used to review NEC's estimates for PWVs:

- Using the costs information submitted directly by Refinery 1 to estimate the PWV would result in \$41 M.

- Using NEC's approach and NEC's equation shown below to estimate the PWV would result in \$52 M. The PWV estimated based on NEC's approach and equation would be about 26% higher than that estimated using the actual costs submitted by Refinery 1.

  $\text{PWV} = 3.204 \text{ x Feed Rate}^{0.6109} = 3.204 * 95^{0.6109} = \$52 \text{ M}$
  $\text{Ratio} = \$52 \text{ M} / \$41 \text{ M} = 1.26$

- Using NEC's equation to back-estimate the feed rates, and comparing those with 1) the feed rates reported by the refineries in the SOx RECLAIM reports, and 2) the feed rates posted on the federal U.S. Energy (www.eia.gov) website presented at the January 22, 2014 WGM. As shown in Table F.1, NEC had used incorrect feed rates for all refineries.

Table F. 1 - Refinery Feed Rates of FCCUs in SCAQMD

Refinery No.	4	8	9	5	6
NEC's PWV, \$M	38	42	39	46	46
Back-calculated feed rates used by NEC, 10^3 Barrels/Day	58	68	60	79	79
Feed rates reported in SOx RECLAIM, 10^3 Barrels/Day	30	55	55	71	90
Feed rates shown in the Jan 22 14 WGM, 10^3 Barrels/Day	34	49	52	67	84

- After adjusting the NEC's estimates to the correct feed rates and reducing the NEC's estimates by 26% to reflect the PWVs that were equivalent to the actual costs reported by Refinery 1 for its SCR, the results would be as shown in Table F.2 below.

- The revised cumulative PWV would be $154 M, within the range of AQMD's estimate presented in the WGM on January 22, 2014 of $152 M.

Table F. 2 – Estimates of Costs Adjusting to Refinery Feed Rates

	Feed Rate (10^3 Barrels/D)	AQMD's Estimates ($M)	Revised NEC's Estimates ($M)	Ratio NEC/ AQMD
Ref 5	71	33	34	1.03
Ref 6	90	57	40	0.70
Ref 7	55	27	29	1.07
Ref 4	34	16	22	1.38
Ref 9	55	19	29	1.53
Total		**152**	**154**	**1.01**

Review Using Vendor's Information for Refinery 9's SCR

NEC received a verbal estimate of costs from a prominent SCR manufacturer for Refinery 9's SCR to meet 2 ppmv NOx. The manufacturer's design was for a system with 2 layers of catalysts and 1 spare layer. Catalyst volume = 3,300 cubic feet. Space velocity = 4197 hr-1.

NEC modified the manufacturer's design and increased the SCR costs provided by the manufacturer by three steps:

1. Enlarging the SCR size and filling all 3 layers with catalysts. The total catalyst volume was increased to 12,697 cubic feet, about 3.85 times more catalysts than the manufacturer's design. Space velocity was reduced by 3.85. Space velocity = 1,091 hr-1.

2. Adding a "markup" factor, or a bid conditioning factor of 1.35 to increase the costs

3. Adding another 75% increase in labor to the costs of the manufacturer's SCR.

NEC did not provide any references to their markup factors and simply stated that they were based on NEC's experience.

Increasing catalyst volume and reducing space velocity are not justified

As shown in Table F.3 below, Refinery 6's SCR and Refinery 5's SCR are designed to meet 5 ppmv. The catalyst volumes are in a range of 2,391 - 3,100 cubic feet with space velocity range from 2,974 -

6,400 hr-1. To reach a level of 2 ppmv NOx, several major SCR manufacturers including Mitsubishi, Cormetech, Haldor Topsoe, and Johnson Matthey indicated that about 10% more catalysts is needed. Thus the catalyst volumes for 2 ppmv SCR would be about 2,630 – 3,410 cubic feet. The manufacturer recommended 3,300 cubic feet for Refinery 9's SCR. Refinery 9 has about 30 - 50% less feed rate than Refinery 1, 5 and 6, thus staff felt that 3,300 cubic feet was sufficient. As shown in Table F.3, the space velocity varies widely with manufacturers and SCR designs, but all SCRs for FCCUs have 2 layers of catalysts. Thus, increasing the catalyst volume and reducing the space velocity as NEC recommended are not necessary.

Table F. 3 – Performance Information of Existing SCRs

	Refinery 1	Refinery 6	Refinery 5
FCCU Feed Rate (10^3 Barrels/day)	95	84	71
SCR Manufacturer	1	2	3
No of SCR layers	2	2	2
Catalyst volume (ft3)	6,200	3,100	2,391
Design NOx levels (ppmv)	10	5 - 6	5 - 6
NOx measured (ppmv)	2	5.6 - 6.4	15 (note)
Space velocity (hr-1)	3,951	6,400	2,974

Note: There are 2 SCRs in parallel for Refinery 5, 1 SCR is in use and 1 standby

Increasing the costs by adding two layers of "markup" is not justified

Markups are reasonable if the control equipment has not yet been used widely for the category of sources. In this case, the manufacturer provided NEC information on costs has substantial experiences in designing and building SCRs for the refinery FCCUs. Staff does not feel that the markup factors of 1.35 and 75% increase are necessary.

Revised PWVs

Table F.4 includes the Total Installed Costs and PWVs estimated for Refinery 9 under several scenarios. NEC's design of 3 layers of catalysts and 2 "markups" resulted in TIC of $31.6 M, and PWV of $39 M. The manufacturer's design of 2 layers of catalysts and no markup resulted in TIC of $15.5 M and PWV of $21M compared to AQMD's estimates of TIC of $16.13 M and PWV of $19 for Refinery 9's SCR.

Table F. 4 - Comparison of Costs Estimates for Refinery's SCR

	NEC's Design	Manufacturer's Design				AQMD's Approach
Layers of catalysts	3	2	2	2	2	with 50%
1.35 Markup	Yes	Yes	No	Yes	No	Contingency
75% Markup	Yes	Yes	Yes	No	No	
Total Installed Costs , $M	**31.6**	**26.4**	**21.5**	**18.3**	**15.5**	**16.13**
PWV, $M	**39**	**32**	**27**	**24**	**21**	**19**

The PWV for the manufacturer's design with no markup of $21 M was only 10% more of AQMD's estimates using the EPA OAQPS Control Cost Manual Guidelines, 6th Edition, January 2002. Note that AQMD used 50% contingency to account for the uncertainty in the complex refinery environment while the EPA OAQPS Guidelines recommended a level of 30%.

Table F.5 shows the PWVs for all 5 SCRs. Even with a two levels of markup, the total revised PWVs would be about $163 M, within +10% of AQMD's estimates of $152 M.

Table F. 5 - Comparison of Costs Estimates for SCRs with and without MarkUps

	Feed Rate (10^3Barrels per Day)	AQMD's Estimates PWV ($M)	Manufacturer's costs with 2 layers of catalysts and no markups PWV = 1.825*FR^0.6 ($M)	Manufacturer's costs with 2 layers of catalysts and 2 levels of markups PWV = 2.8013*FR^0.6 ($M)
Ref 5	71	33	24	36
Ref 6	90	57	27	42
Ref 7	55	27	20	31
Ref 4	34	16	15	23
Ref 9	55	19	20	31
Total		**152**	**106**	**163**

Conclusions

1. AQMD's estimates reflect the costs for SCRs with 2 layers of catalysts and 1 spare layer. This SCR arrangement can achieve 2 ppmv NOx. Refinery 1's SCR achieves 2 ppmv with 2 layers of catalysts and 1 spare layer.

2. NEC used incorrect feed rates in the estimates.

3. NEC's recommendation of reducing the velocity to 10 feet per second and using 3 layers of catalysts that result in 3.85 times more catalysts than recommended by the manufacturer is not justified.

4. NEC's approach of adding two layers of markups to the manufacturer's costs may be highly conservative.

5. The AQMD's estimate for cumulative PWV of $152 M can be expressed as $152 M ± 50%. With the incorrect feed rates, high volume of catalysts and high markups, NEC estimated a cumulative PWV of $211 M which was within +50% of AQMD's estimate $152 M. NEC's estimates however should be adjusted for the feed rates and should be reduced to reflect the amount of catalysts recommended by the manufacturer.

Appendix G – Review of NEC's Analysis for Refinery Boilers and Heaters

NEC recommended a BARCT level of 2 ppmv for refinery boilers/heaters with rating >40 mmbtu/hr. However, NEC's estimates for PWVs of SCR were about 3 to 4 times higher than staff's estimates as shown in Figure G.1, presented at the July 31, 2014 Working Group Meeting. The purpose of this Appendix is to analyze NEC's approach, explain the differences in the two estimates, and provide recommendations to reconcile the numbers, if possible. Note that since the 2005 BARCT level for boilers/heaters with rating >110 mmbtu/hr is 5 ppmv, NEC provided two cost curves for SCRs that could meet 2 ppmv and 5 ppmv NOx so that the "incremental" costs for boilers/heaters >110 mmbtu/hr could be determined.

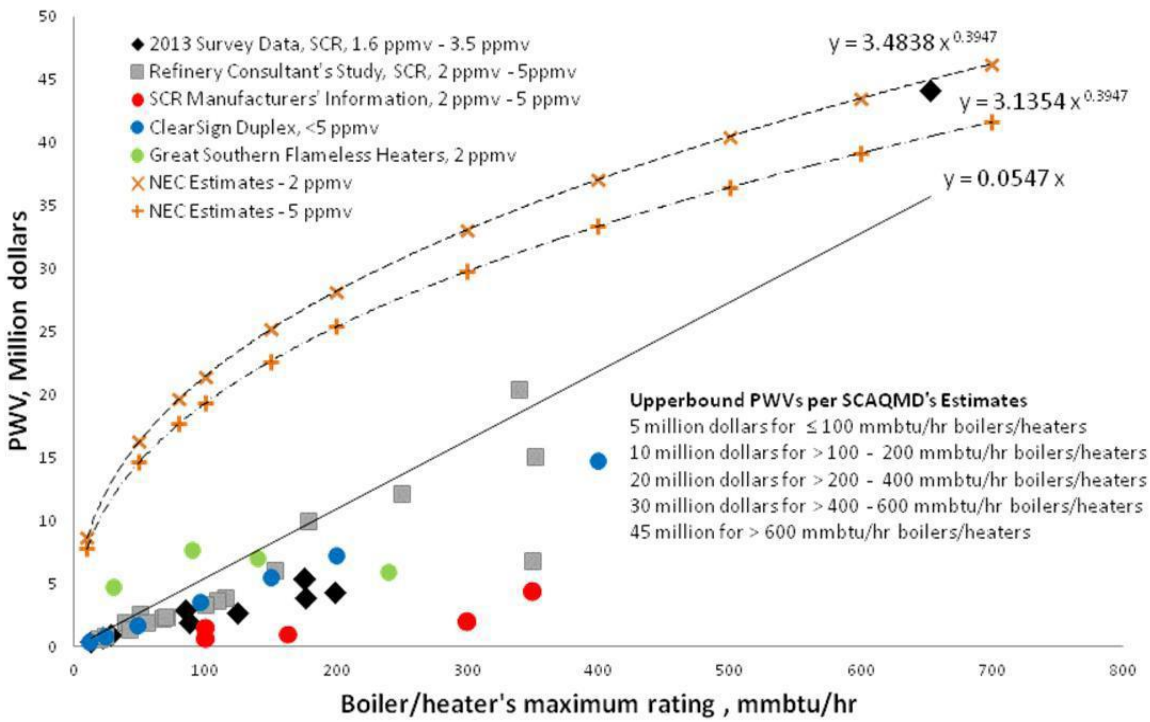

Figure G. 1 - Present Worth Values for SCRs (December 2014)

Summary of Staff's Approach

- Cost data for all feasible control technologies including SCRs, LoTOx, Great Southern flameless heaters, and ClearSign duplex burners was analyzed.

- Three sets of cost data were used to construct the cost curve in Figure G.1:

  — Group 1 data set: Survey cost data provided directly by the refineries for SCRs that achieved 1.6 – 3.5 ppmv NOx was used. The refineries provided actual equipment costs, total installed costs (TIC) and annual operating costs. The actual costs were escalated to today dollars. From this set of actual costs: TIC = 3.87 x equipment costs, and PWV = 1.052 x TIC = 4.07 x equipment costs

  — Group 2 data set: Cost data estimated by the consultants of the refineries for future SCR projects was used. The consultants of the refineries applied a factor of 4.0 to estimate TICs for future projects (i.e. TIC = 4.0 x equipment costs), and staff estimated the PWVs consistently with the actual costs data in Group 1, PWV = 1.052 x TIC.

  — Group 3 data set: Equipment costs provided by control equipment manufacturers for SCRs, Great Southern Flameless heaters, and ClearSign Duplex burners were used. TICs were estimated using a factor of 4.0, and PWVs were estimated using a factor derived from Group 1 data set.

- Staff elected the upperbound PWVs shown in Figure G.1 for the costs of control devices that can achieve 5 ppmv NOx. Staff added another 10% to the upperbound costs in Figure 1 to derive the costs for control devices that can meet 2 ppmv NOx:

  $5.5 M for units with maximum rating ≤ 100 mmbtu/hr
  $11 M for units with maximum rating > 100 – 200 mmbtu/hr
  $22 M for units with maximum rating > 200 – 400 mmbtu/hr
  $33 M for units with maximum rating > 400 – 600 mmbtu/hr
  $49.5 M for units with maximum rating > 600 mmbtu/hr

  The upperboud PWVs derived were higher than all of the actual costs from Group 1, 2 and 3 data set. For example, the actual reported costs for a 650 mmbtu/hr heater was about $42 M and the upperbound PWV that staff derived based on this approach were $49.5 M.

Summary of NEC's Approach

- NEC received a quote for a FCCU SCR of $1.78 M. NEC indicated that the manufacturer recommended a SCR of 20 feet width x 15 feet length x 33 feet height, with 2 beds filled with catalysts and 1 spare bed, designed with 12.8 ft/sec velocity.

- NEC adjusted the manufacturer's design to 10 ft/sec velocity, increased the cross section area, added a 3rd and a 4th layer of catalysts, increased the SCR dimension to 20 feet width x 19.2 feet length x 44 feet height, and increased the equipment costs to $2.48 M.

- NEC used three multiplication factors to estimate TIC: 1.35 to account for a "low" bid conditioning, 1.75 for "additional labor", and 4.5 for installation:

  TIC = ($2.48)(1.35)(1.75)(4.5) = $26.36 M

NEC subdivided the equipment costs into three components and prorated the costs to other sizes of boilers and heaters:

— Steel and box costs were prorated using flue gas flow rates to the 0.6 power
— Catalysts costs were prorated using flue gas flow rates
— Costs for ammonia injection system were kept constant at $0.65 M

NEC then added other costs: $1.5 M for a new CEMS, $1.5 M for a new ammonia system, and $1 M to $5 M for an induced draft fan depending on the size of the heaters and boilers. NEC estimated annual costs for ammonia usage, utility, catalyst replacement, and miscellaneous maintenance. The annual operating costs were about 20%-30% of the PWVs.

Finally, the PWVs were estimated by NEC as follows:

$$\text{PWV} = 3.1354 \times (\text{Maximum rating of boiler or heater})^{0.3947} \text{ for 5 ppmv SCRs}$$
$$\text{PWV} = 3.4838 \times (\text{Maximum rating of boiler or heater})^{0.3947} \text{ for 2 ppmv SCRs.}$$

NEC provided two curves for 2 ppmv SCR and 5 ppmv SCR so that staff could use to estimate the incremental costs for boilers/heaters >110 mmbtu/hr.

Staff's Review

Staff's and NEC's approaches are inherently different. Staff included all feasible control technologies while NEC analysis relied on one quote for a FCCU's SCR and a "factor cost estimation" approach. As shown in Table G.1, NEC's estimates were about 3 – 4 times higher than staff's estimates.

Table G. 1 – Comparison of SCR Costs for Boilers/Heaters Estimated by NEC and Staff

Boiler/Heater rating, mmbtu/hr	40	90	120	250	300	450	500	700
Staff's estimates	5.5	5.5	11.0	22.0	22.0	33.0	33.0	49.5
NCE's estimates	14.9	20.6	23.1	30.8	33.1	38.8	40.5	46.2
Ratio of NEC/Staff	2.7	3.7	2.1	1.4	1.5	1.2	1.2	0.9

Staff's review of NEC's approach is summarized below.

Multiplication factor used for installation costs – minor difference

- NEC used a multiplication factor of 4.5 to estimate the TIC from the equipment costs provided by the manufacturer, i.e. TIC = 4.5 x equipment costs.

- Staff has been criticized for using multiplication factors documented in the EPA OAQPS Costs Guidelines that may not reflect the complex retrofit installations at the refineries. However, staff did not use the factors from the EPA OAQPS Costs Guidelines in this case. The cost curve in Figure G.1 was constructed using three sets of data:

  — In Group 1 set of data, the refineries provided equipment costs and installation costs for actual installations at the refineries. If back-calculated, the multiplication factor for Group 1 would be 3.87.

  — In Group 2, the consultants of the refineries used a multiplication of 4.0 to estimate the TICs for future projects.

  — In Group 3, staff used a multiplication factor of 4.0 to estimate installation costs for equipment provided by the manufacturers to be consistent with Group 1 and 2.

  — Finally, staff elected the upperbound PWVs higher than all Group 1, 2 or 3 data set, which implied that the final factor was above 4.0.

Equipment costs – major difference

The SCR installation is a capital intensive project. About 70% - 85% of the PWV were attributed to the TIC. Since NEC estimated the TIC based on equipment costs (TIC = 4.5 x equipment costs), the significant difference between staff's and NEC's estimates can be attributed to the equipment costs, and more importantly, the basis that NEC used to obtain the costs.

FCCU's catalysts are not designed for refinery boilers and heaters

NEC received a quote for a FCCU SCR, adjusted and prorated this quote to estimate the costs of SCRs for boilers and heaters. The SCR catalysts for FCCU however cannot be used for boilers and heaters. To handle a high dust application such as FCCU, the SCR catalysts are designed to have a catalyst flow passage (or pitch) of about 7 mm. The refinery boiler and heater is a low dust application, and the catalyst pitch for this application is about 3 mm. The SCR for a refinery boiler and heaters is generally compact and contains one layer of catalysts. The FCCU SCR contains 2 to 3 layers of catalysts with a spare layer. The FCCU SCR has a large box area designed to fit additional equipment such as a soot blower. It is not appropriate to prorate the costs of a FCCU SCR to obtain the SCR costs for boiler and heaters.

Two layers of catalysts for FCCU and one layer of catalysts for boilers/heaters for 2 ppmv NOx

NEC elected to use a 10 ft/sec velocity and added two layers of catalysts for the FCCU SCR. As a result, NEC increased the dimension of the SCR and the catalyst volume substantially.

There are several heaters in the SCAQMD that have SCRs built to achieve 5 pppmv NOx, and these SCRs actually achieved 1.6 ppmv – 2.7 ppmv as reported by the refineries. All of these SCRs have 1 layer of catalysts. The catalyst depth is about 2 – 3 feet, and the catalyst volumes range from 62 – 623 cubic feet as shown in Table G-2.

Refinery 1 FCCU SCR achieved less than 2 ppmv NOx. This SCR has 2 layers (not 4 layers) of catalysts with a total catalyst depth of 9 feet (not 24 feet). The dimension of the FCCU's SCR in Table G.2 shows a sharp distinction compared to those for boilers and heaters.

Table G. 2 – Performance Levels and Dimensions of Existing SCRs for Heaters in SCAQMD

	Ref 9 3 hydro treating heaters	Ref 5 isomax heater	Ref 5 crude heater	Ref 9 crude heater	Ref 5 3 coker heaters	Ref 5 4 ref-ormers	Ref 1 FCCU
Maximum rating, mmbtu/hr	63	78	83	85	528	589	95,000 B/D
NOx, survey, ppmv	**2.7**	**2.3**	**2.3**	**3.3**	**2.7**	**1.6**	**< 2ppmv**
NOx, permit limit, ppmv	n/a	5	5	5	n/a	5	
SCR, Width, ft	5	20	4	17	18	13	30
SCR, Length, ft	6	7	6	7	18	16	29
SCR, Height, ft	4	6	3	12	20	3	49
Total SCR volume, ft3	110	798	note 1	1,380	6,300	note 1, 2	41,748
Existing catalyst volume, ft3	92	92	62	96	623	537	**6,210**
No of catalyst layers	1	1	1	1	1	1	**2 (1 spare)**
Catalyst depth, ft	3	2	3	2	2	3	**4.5**

Note:
1) The SCR height stated in the permit is likely for the catalsyts and not for the overall SCR .
2) District recently approved a change of catalysts for this SCR. New catalyst volume is 424 ft3, guarantee of <=5 ppmv NOx

Theoretical estimation of catalyst volume

A theoretical equation can be derived to estimate the amount of catalysts needed to achieve 2 ppmv NOx for boilers and heaters starting with a theoretical equation used to describe the SCR NOx control efficiency shown below: [6]

$$\eta = m\,(1 - \exp(-\frac{k}{SV})$$

Where:

η = NOx removal efficiency = $\frac{NOx\ in - NOx\ out}{NOx\ in}$

m = molar ratio of NH3 to NOx at the SCR inlet = $\frac{NH3\ in}{NOx\ in}$

k = kinetic constant, 1/time

SV = space velocity, 1/time = $\frac{flue\ gas\ flow\ rate}{catalyst\ volume}$ = Q/V

[6] EPA OAQPS Air Pollution Control Cost Manual, Chapter 2, Selective Catalytic Reduction, October 2000, and SCR Performance on a Hydrogen Reformer Furnace – Technical Paper, Journal A&WMA, Vol. 48, January 1998, R. Kunz.

Rearranging the equation to estimate the catalyst volume:

$$V = \left(\frac{Q}{k}\right)(-\ln(1 - \frac{\eta}{m})$$

Catalyst volume for a SCR designed to achieve 2 ppmv and 5 ppmv NOx:

$$V\ for\ 2\ ppmv\ NOx = \left(\frac{Q}{k}\right)(-\ln(1 - \frac{\eta\ for\ 2\ ppmv\ NOx}{m})$$

$$V\ for\ 5\ ppmv\ NOx = \left(\frac{Q}{k}\right)(-\ln(1 - \frac{\eta\ for\ 5\ ppmv\ NOx}{m})$$

Catalyst volume needed to achieve 2 ppmv NOx can be estimated from the catalyst volume of a SCR designed to reach 5 ppmv NOx using the following equation:

$$\frac{V\ for\ 2\ ppmv\ NOx}{V\ for\ 5\ ppmv\ NOx} = \frac{\ln\left(1 - \frac{\eta\ for\ 2\ ppmv\ NOx}{m}\right)}{\ln\left(1 - \frac{\eta\ for\ 5\ \ ppmv\ NOx}{m}\right)}$$

A spreadsheet calculation shown in Table G.3 was used to estimate the amount of catalyst volume required to achieve 2 ppmv outlet NOx concentrations from NOx inlet concentrations ranging from 25 ppmv to 500 ppmv for several scenarios where m equals to 1, 1.05 and 1.1.

As shown in Table G.3, where m = 1, NOx inlet concentration = 100 ppmv, the catalyst volume to achieve 2 ppmv NOx would be about 31% more than the catalyst volume to achieve 5 ppmv NOx. Where m = 1.05 and 1.10, only 15% and 11% additional catalysts would be needed, respectively.

The results in Table G.3 showed that the higher the molar ratio of NH3 to NOx, the smaller the additional amount of catalysts would be required.   The ammonia slips for m = 1 would be 0 ppmv and about 2 ppmv for m =1.1. The results in Table G.3 also showed that the catalysts were more effective at higher level of NOx inlet concentrations. Where m was 1.1 and NOx inlet concentrations were 200 ppmv or more, less than 2% - 6% of additional catalysts would be needed to reach 2 ppmv NOx.

Table G. 3 – Estimation of Catalyst Volumes for SCRs

Where m = 1										
NOx in	NOx out	NOx out	(NOx in - NOx out of 5 ppmv) / NOx in	(NOx in - NOx out of 2 ppmv) / NOx in	m	m	ln (1 - η/m) for 5 ppmv	ln (1 - η/m) for 2 ppmv	Cat Vol for 5 ppmv	Cat Vol for 2 ppmv
500	5	2	0.990	0.996	1.00	1.00	-4.61	-5.52	1.00	1.20
400	5	2	0.988	0.995	1.00	1.00	-4.38	-5.30	1.00	1.21
300	5	2	0.983	0.993	1.00	1.00	-4.09	-5.01	1.00	1.22
200	5	2	0.975	0.990	1.00	1.00	-3.69	-4.61	1.00	1.25
100	5	2	0.950	0.980	1.00	1.00	-3.00	-3.91	1.00	1.31
75	5	2	0.933	0.973	1.00	1.00	-2.71	-3.62	1.00	1.34
50	5	2	0.900	0.960	1.00	1.00	-2.30	-3.22	1.00	1.40
25	5	2	0.800	0.920	1.00	1.00	-1.61	-2.53	1.00	1.57
Where m = 1.05										
500	5	2	0.990	0.996	1.05	1.05	-2.86	-2.97	1.00	1.04
400	5	2	0.988	0.995	1.05	1.05	-2.82	-2.95	1.00	1.05
300	5	2	0.983	0.993	1.05	1.05	-2.76	-2.92	1.00	1.06
200	5	2	0.975	0.990	1.05	1.05	-2.64	-2.86	1.00	1.08
100	5	2	0.950	0.980	1.05	1.05	-2.35	-2.71	1.00	1.15
75	5	2	0.933	0.973	1.05	1.05	-2.20	-2.62	1.00	1.19
50	5	2	0.900	0.960	1.05	1.05	-1.95	-2.46	1.00	1.26
25	5	2	0.800	0.920	1.05	1.05	-1.44	-2.09	1.00	1.46
Where m = 1.10										
500	5	2	0.990	0.996	1.10	1.10	-2.30	-2.36	1.00	1.02
400	5	2	0.988	0.995	1.10	1.10	-2.28	-2.35	1.00	1.03
300	5	2	0.983	0.993	1.10	1.10	-2.24	-2.33	1.00	1.04
200	5	2	0.975	0.990	1.10	1.10	-2.17	-2.30	1.00	1.06
100	5	2	0.950	0.980	1.10	1.10	-1.99	-2.22	1.00	1.11
75	5	2	0.933	0.973	1.10	1.10	-1.89	-2.16	1.00	1.15
50	5	2	0.900	0.960	1.10	1.10	-1.70	-2.06	1.00	1.21
25	5	2	0.800	0.920	1.10	1.10	-1.30	-1.81	1.00	1.39

To be very conservative, use a factor of 1.3 (m = 1, NOx in = 100 ppmv) to estimate the additional amount of catalysts needed to meet 2 ppmv from the existing SCRs designed for 5 ppmv NOx:

$$V\ for\ 2\ ppmv\ NOx = \ 1.3\ x\ V\ for\ 5\ ppmv\ NOx$$

A comparison of the theoretical estimates and NEC's design for 2 ppmv SCRs is shown in Table G-4. This comparison shows that NEC design resulted in catalysts volume of 6 – 13 times higher than necessary.

Table G. 4 - SCR Dimensions, Catalyst Volumes, and Number of Layers Estimated by NEC and Staff for 2 ppmv SCRs

	Ref 9 3 hydro treating heaters	Ref 5 isomax heater	Ref 5 crude heater	Ref 9 crude heater	Ref 5 3 coker heaters	Ref 5 4 ref-ormers	NEC Design for SCR to achieve 2 ppmv NOx				
Maximum rating, mmbtu/hr	63	78	83	85	528	589	40	91	126	309	527
NOx, survey, ppmv	**2.7**	**2.3**	**2.3**	**3.3**	**2.7**	**1.6**					
NOx, permit limit, ppmv	n/a	5	5	5	n/a	5					
SCR, Width, ft	5	20	4	17	18	13	6	8	9.8	15	19
SCR, Length, ft	6	7	6	7	18	16	5	8	9	14	19
SCR, Height, ft	4	6	3	12	20	3	44	44	44	44	44
Total SCR volume, ft3	110	798	note 1	1,380	6,300	note 1, 2	1,234	2,816	3,881	9,504	16,218
Existing catalyst volume, ft3	92	92	62	96	623	537					
No of catalyst layers	1	1	1	1	1	1					
Catalyst depth, ft	3	2	3	2	2	3					
Estimated volume of catalysts for 2 ppmv NOx = 1.3 * existing catalyst volume, ft3	**120**	**101**	**68**	**106**	**685**	**590**	**679**	**1,549**	**2,135**	**5,227**	**8,920**
No of catalyst layers	**1**	**1**	**1**	**1**	**1**	**1**	**4**	**4**	**4**	**4**	**4**
Estimated catalyst depth, ft	**4**	**3**	**3**	**2**	**2**	**3**	**24**	**24**	**24**	**24**	**24**

Note:
1) The SCR height stated in the permit is likely for the catalsyts and not for the overall SCR .
2) District recently approved a change of catalysts for this SCR. New catalyst volume is 424 ft3, guarantee of <=5 ppmv NOx

Four layers of catalysts and SCRs with 44 ft high are excessive

Note that there are many types of SCR catalysts for boilers and heaters. The optimized volume of catalysts, dimension of SCRs, space velocity, and direction of flue gas flow (vertical or horizontal) may vary with each manufacturer and design. Table G.5 shows a design provided by a prominent SCR manufacturer for 100 mmbtu/hr and 300 mmbtu/hr heaters which shows that one layer of catalysts of would be sufficient to meet 2 ppmv NOx.

The differences in staff's and NEC's estimates for catalyst volume, SCR box surface area, and SCR box volume are depicted in Figures G.2, G.3 and G.4. The catalyst volumes estimated by NEC were approximately 14 times higher than the actual amount. The SCR box surface areas and volumes that NEC designed were about 2.6 times larger than needed.[7]

[7] To estimate steel costs and support, NEC used the flue gas flow rates to the 0.6 power, other engineering approaches use the SCR surface areas to the 0.5 power.

Table G. 5 – SCR Dimensions, Catalyst Volumes, and Number of Layers Estimated by Manufacturer for 2 ppmv and 5 ppmv SCRs

Heater rating, mmbtu/hr	100	100	300	300
NOx inlet, ppmv	100	100	100	100
NOx outlet, ppmv	5	2	5	2
Catalyst layer	1	1	1	1
Catalyst volume, cubic feet	74	92	240	293
Catalyst depth, feet	1	1	2.5	3
SCR dimension, Width, feet	10 x 10	10 x 10	10 x 10	10 x 10
SCR dimension, Height, feet	13.4	13.4	20	20
Total SCR volume, cubic feet	1340	1340	2000	2000
Note: SCR can be horizontal or vertical flow				

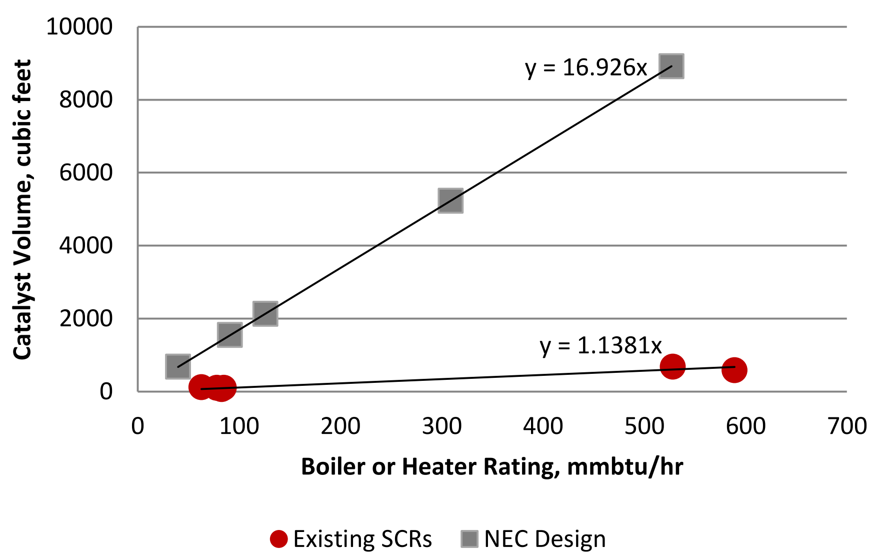

Figure G. 2 - Catalyst Volumes

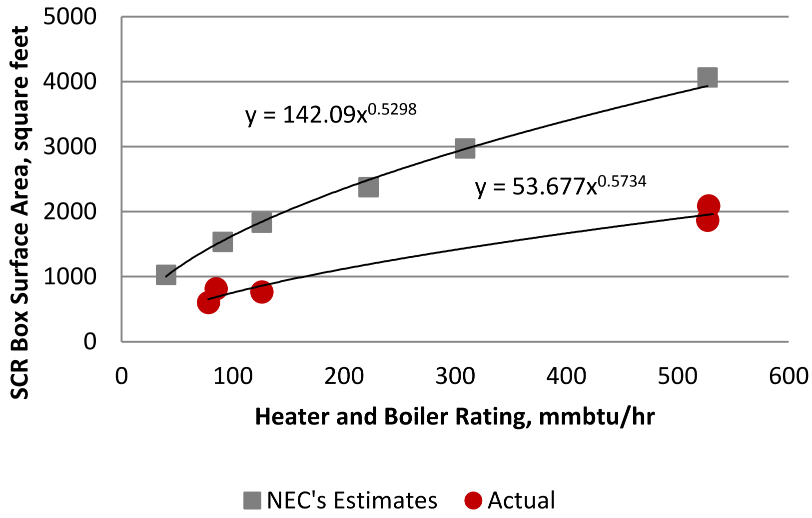

Figure G. 3 - SCR Box Surface Areas

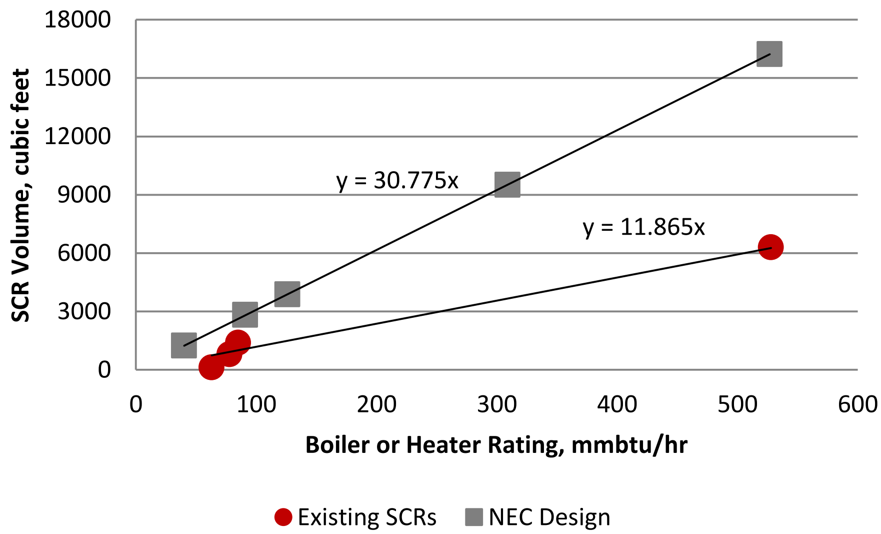

Figure G. 4 - SCR Box Volumes

Staff's estimates based on actual existing SCR's dimensions shown in Table G.4, Figures G.2, G.3 and G.4 were in agreement with existing SCR design at a refinery and manufacturer's estimates. See Table G.6 for a comparison.

Table G. 6 – SCR Dimensions, Catalyst Volumes, and Number of Layers Estimated by Staff, NEC and SCR Manufacturer for 2 ppmv SCR

	Staff's estimates	Manufacturer's estimates	NEC's estimates	Existing 589 mmbtu/hr meeting 2 ppmv NOx
No of catalyst layer	1	1	4	1
Catalyst depth, feet	3	3	24	3
Catalyst volume, cubic feet	341	293	5078	537
Estimated SCR dimension, feet	12x12x25	10x10x20	15x14x44	13x16x3
SCR surface area, square feet	1439	1000	2917	---
SCR total volume, cubic feet	3559	2000	9232	624

The high costs estimated by NEC for steel box, steel support, catalysts, ID fan, catalyst replacement, and subsequently installation costs and annual operating costs were the results of NEC's inaccurate approach in design. NEC's estimates were not consistent with existing achieved-in-practice SCR and manufacturer's standards.

High estimates for new CEMS

NEC estimated $1.5 M for CEMS replacement for each boiler and heater. Based on information received from the SCAQMD's Technology Advancement Office, CEMS upgrades will be needed to measure 2 ppmv NOx. Upgrades can vary between a change in existing analyzer range to a full CEMS replacement. The cost estimates for CEMS upgrades that the refineries provided to the SCAQMD on their CEMS applications were highly variable. For example, a refinery cited $270,000 for an analyzer replacement, but other applications showed that they also provided $20,000 - $60,000 estimates for analyzer replacement. A realistic average estimate for an installed replacement analyzer cost is in the range of $20,000 – $60,000 per CEMS, based on the most prevalent information that the SCAQMD received on CEMS applications.

High bias for boilers and heaters with rating <300 mmbtu/hr

In NEC's analysis, NEC kept the costs for ammonia injection system constant at $0.65 M for all size of heaters and boilers. Table G.7 shows the itemized distribution of costs for various sizes of boilers and heaters. The ammonia injection system contributed to about 72% of the equipment costs for a 40 mmbtu/hr heater, and 27% for a 527 mmbtu/hr heater.

Table G. 7 – Costs of Ammonia Injection System and Its Impact on the Overall Cost of SCR

Equipment Costs Itemized								
Boiler/Heater Rating, mmbtu/hr	40	91	126	202	309	527	800	1,000
SCR Box, $M	0.15	0.25	0.31	0.41	0.53	0.73	0.93	1.07
NH3 Injection System, $M	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
Box Steel, $M	0.03	0.06	0.07	0.09	0.11	0.16	0.20	0.23
Catalyst, $M	0.07	0.15	0.21	0.34	0.52	0.88	1.34	1.68
Total, $M	0.91	1.11	1.24	1.49	1.81	2.42	3.13	3.64
Distribution of Costs								
SCR Box, % of costs	17%	23%	25%	27%	29%	30%	30%	29%
NH3 Injection System, % of costs	72%	58%	53%	44%	36%	27%	21%	18%
Box Steel, % of costs	4%	5%	5%	6%	6%	7%	6%	6%
Catalyst, % of costs	7%	14%	17%	23%	29%	37%	43%	46%
Total, %	100%	100%	100%	100%	100%	100%	100%	100%
Present Worth Values								
Staff estimates, $M	5	5	10	20	20	30	45	45
NEC estimates, $M	15	21	24	28	33	41	49	53
Difference of NEC/Staff	3	4	2	1.4	2	1.4	1.1	1.2

Keeping the costs of ammonia injection system constant at $0.65 M created a disproportion in NEC's estimates for smaller sizes boilers and heaters. As a result, NEC's PWVs were about 3-4 times higher than staff's estimates for units < 100 mmbtu/hr, 2 times or less for units 150 – 500 mmbtu/hr, but only 1.4 times or less for units >500 mmbtu/hr.

Annual operating costs – difference due to catalyst replacement costs

- NEC estimated annual costs for ammonia usage, utility, catalyst replacement, and miscellaneous maintenance costs. The annual operating costs for 25 years life of the SCR were about 12% - 37% of the PWVs. Catalyst replacement contributed 50% - 60% of the annual operating costs.

- Based on data reported directly from the refineries, the annual operating costs were about 5% of the PWVs. Based on manufacturers' information, the catalyst replacement costs were about 5% - 10% of the annual operating costs. The high costs of NEC's estimates for annual operating costs are due mainly to the costs associated with catalyst replacement for 4 layers of catalysts.

Staff's estimates of PWVs are conservative

Table G.8 shows an example to demonstrate the conservative in staff's estimate. Refinery 5 reported the following costs for a SCR measured 1.6 ppmv NOx for 4 heaters:

Capital costs = $1.95 million[8] (1994 dollars)
Installation = $5.85 million (1994 dollars)
Annual operating = $30,000
Marshall Index = 1.56
Total Installed Costs = 1.56 ((1.95 + 5.85) + (15.62 * 30,000)) = $ 13 M

Table G. 8 – SCR Costs Estimated by Staff and NEC for Four Process Heaters Vented to a Common Stack

Heater	Rating mmbtu/hr	Staff's Approach Upperbound PWV	NEC's Approach PWV
D471	177	$11 M	$27 M
D472	125	$11 M	$23 M
D473	88	$5.5 M	$20 M
D3031	199	$11 M	$28 M
Total		***$38.5 M***	***$99 M***

NEC's estimates were 8 times higher than actual reported costs. Staff's estimates using (1.10 x upperbound PWVs) were 3 times higher than actual costs reported from Refinery 5.

Staff estimated that all control projects for refinery boilers and heaters would cost approximately $254.5 M with 103 cost-effective boilers and heaters. Had staff included an analysis for SCRs that could be shared between boilers and heaters, the overall costs for this category would be less than $254.5 M, and SCRs could become cost-effective for boilers and heaters with rating <40 mmbtu/hr that could share a SCR with other units.

Conclusions

1. Staff used a different approach to estimate the SCR costs for boilers/heaters because:

— The SCR catalysts for FCCUs were not equivalent to the SCR catalysts for boilers and heaters, and NEC's approach of prorating the costs of FCCU's SCR to boiler/heater's SCR was inappropriate.

— NEC's design of 44-feet high SCRs with 4 layers of catalysts for all boilers and heaters to achieve 2 ppmv NOx was not consistent with manufacturers' standards and information of

[8] In the permit application for this SCR, Refinery 5 reported a TIC of $609,000 including a new SCR, SCR catalysts with engineering, procurement, construction, supports and demo, tax (8.5%), and freight (3%). Thus, the $1.95 M would be assumed to include all other miscellaneous peripheral equipment such as ID fan, ammonia tank, and CEMS.

existing SCRs available in the facility permit database. NEC's analysis resulted in high equipment costs, steel costs, catalysts costs, installation costs, and catalyst replacement costs.

— NEC's estimate for new CEMS was not consistent with previous applications submitted in RECLAIM.

— NEC's approach of keeping the costs of ammonia injection system constant at $0.65 M for all sizes of boilers and heaters resulted in high costs for boilers and heaters rating less than 300 mmbtu/hr.

2. Staff's analysis included all feasible control technologies, and were based on a large set of costs data including 1) actual costs reported from the refineries, 2) cost data estimated by the consultants contracted by the refineries, and 3) cost data provided by a variety of control manufacturers including SCR, Great Southern flameless heaters, and ClearSign. The upperbound PWVs ± 50% were reasonable.

3. NEC's site visits at the refineries were helpful in locating available space for SCRs. NEC identified 6 heaters with installation challenge, and recommended a 20% - 25% increase to the TICs of these heaters. Staff concurred with NEC recommendation and removed these heaters from further analysis. In addition, staff added costs for fan and ammonia tanks as estimated by NEC, and costs for new CEMS to the costs of the SCRs in Group 3, which raised Group 3's costs closer to other costs shown in Figure G.5.

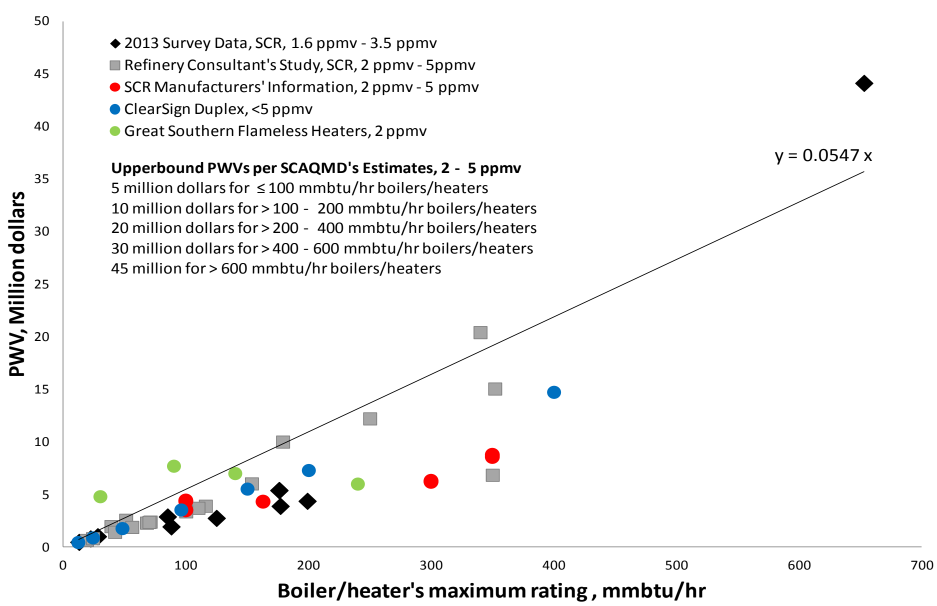

Figure G. 5 - Revised Present Worth Values for SCRs (March 2015)

Appendix H – Review of NEC's Analysis for SRU/TG Incinerators

The purpose of this review is to analyze NEC's approach, explain the differences in the estimates compared to staff's analysis, and provide recommendations to reconcile the numbers, if possible.

Summary of Staff's Approach

- Cost data for all feasible control technologies including SCR, LoTOx, and KnowNOx were analyzed. SCR and LoTOx are used in refinery applications such as boilers, heaters, and FCCU while KnowNOx currently does not yet have any refinery application.

- Process information of three representative scenarios was sent to 2 SCR manufacturers, MECS (LoTOx), and KnowNOx. Cost data provided by the manufacturers and the EPA OAQPS Guidelines were used to estimate the Total Installed Costs (TIC). This approach was used in the 2005 RECLAIM rule amendment.

  Instrumental = 10% x Equipment costs
  Sales Tax = 9% x Equipment costs
  Freight = 5% x Equipment costs
  Total Equipment Costs = 1.24 x Equipment costs
  Installation = 50% x Total Equipment Costs
  Total Installation Costs = (1.5) x Total Equipment Costs = 1.5 x 1.24 x Equipment Costs = 1.86 x Equipment Costs

- The SCR manufacturers also provided other pertinent information such as the SCR overall dimension and the number of catalyst layers needed to achieve 2 ppmv for a SRU/TG incinerator application.

- A contingency factor of 1.5 was used to cover any uncertainty in the estimated costs.

Summary of NEC's Approach

- NEC received a quote for a FCCU's SCR of $1.78 M. NEC indicated that the manufacturer recommended a SCR of 20 feet width x 15 feet length x 33 feet height, with 2 beds filled with catalysts and 1 spare bed, designed with 12.8 ft/sec velocity.

- NEC adjusted the manufacturer's design to 10 ft/sec velocity, increased the cross section area, added a 3rd layer of catalysts, increased the SCR dimension to 20 feet width x 19.2 feet length x 44 feet height, and the equipment costs to \$2.27 M.

- NEC used three multiplication factors to estimate TIC: 1.35 to account for a "low" bid conditioning, 1.75 for "additional labor", and 4.5 for installation:

  TIC = (\$2.27)(1.35)(1.75)(4.5) = \$24.10 M

- NEC subdivided the equipment costs into three components and prorated the costs to other sizes of boilers and heaters:
  - Steel and box costs were prorated using flue gas flow rates to the 0.6 power
  - Catalysts costs were prorated using flue gas flow rates
  - Costs for ammonia injection grid were prorated using flue gas flow rates to the 0.6 power. Note this inconsistent approach in NEC's analysis: NEC kept the costs of ammonia injection constant at \$0.65 M for all sizes of boilers and heaters while prorated the costs for SRU/TG incinerators

- Finally, NEC added other costs: \$1.5 M for a new CEMS, \$1.5 M for a new ammonia system, and \$2.6 M to \$3.98 M for a waste heat boiler when appropriate. NEC estimated annual costs for ammonia usage, utility, catalyst replacement, and miscellaneous maintenance.

Staff's Review

Staff's and NEC's approaches are inherently different. Staff included all feasible control technologies while NEC analysis relied on one quote for a FCCU's SCR and prorated the costs to the SRU/TG applications. As shown in Table H.1, NEC's estimates were about 1.4 – 3.7 times higher than staff's estimates, and overall NEC's estimated PWVs were 2 times higher than staff's estimates (i.e. 96.4/48.7 = 2).

Table H. 1 – SCR Costs Estimated by NEC and Staff for SRU/TGTUs

Fac ID	Dev	AQMD (\$M)	Reductions (tpd)	AQMD CE (\$/ton)	NEC (\$M)	Reductions (tpd)	NEC CE (\$/ton)	Ratio of NEC (\$M) / AQMD (\$M)
6	D952	7.0	0.05	14,247	22.2	0.05	48,658	3.2
5	911/913	7.0	0.05	14,458	9.5	0.05	20,822	1.4
5	927/929	7.0	0.03	28,742	9.6	0.03	35,068	1.4
5	955/957	7.0	0.07	10,967	10.3	0.07	16,125	1.5
1	910	7.0	0.06	13,840	25.5	0.06	46,575	3.7
1	2413	7.0	0.03	26,193	*23.2*	*0.03*	*88,280*	*3.3*
8	294	7.0	0.06	11,805	19.3	0.06	36,720	2.8
Total for cost-effective units		48.7	0.35	15,233	96.4	0.32	33,014	

Staff's review of NEC's approach is summarized below.

Multiplication factor used for installation costs – major difference

- NEC used a multiplication factor of 4.5 to estimate the TIC from the equipment costs provided by the manufacturer (TIC = 4.5 x equipment costs).

- Staff has been criticized in the past for using multiplication factors documented in the EPA OAQPS Costs Guidelines that may not reflect the complex retrofit installations at the refineries. In this case, staff used a multiplication factor of 1.86 derived from the EPA OAQPS Costs Guidelines with an additional 50% contingency factor. The 1.86 was consistent with the approach used in the 2005 NOx RECLAIM rule amendment (i.e. TIC = 1.86 x equipment costs). Please see discussion below for the scenario where staff used a factor of 4.5 to estimate TIC.

Equipment costs – major difference

The SCR installation is a capital intensive project. About 70% - 85% of the PWV were attributed to the TIC. Since NEC estimated the TIC based on equipment costs (i.e. TIC = 4.5 x equipment costs), the significant difference between staff's and NEC's estimates can be attributed to the equipment costs, and more importantly, the basis that NEC used to obtain the costs.

FCCU's catalysts are not designed for SRU/TG incinerators

NEC received a quote for a FCCU SCR, adjusted and prorated this quote to estimate the costs of SCRs for SRU/TG incinerators. The SCR catalysts for FCCU however cannot be used for boilers and heaters. To handle a high dust application such as FCCU, the SCR catalysts are designed to have a catalyst flow passage (or pitch) of about 7 mm. The SRU/TG incinerator is a low dust application, and the catalyst pitch for this application is about 3 mm. The SCR for a SRU/TG incinerator designed by SCR manufacturers is compact and contains one layer of catalyst. The FCCU SCR contains 2 to 3 layers of catalysts with a spare layer. The FCCU SCR has a large box area designed to fit additional equipment such as a soot blower. It is not appropriate to prorate the costs of a FCCU SCR to obtain the SCR costs for incinerators.

Three layers of catalysts is excessive

NEC elected to use a 10 feet/sec velocity and recommended 3 layers of catalysts for the FCCU SCR. NEC then prorated the costs of the FCCU SCR to other incinerators. For Refinery 6, NEC reduced to 2 layers of catalysts because the inlet NOx concentration from the SRU/TG incinerators was <10 ppmv. For other refineries with inlet concentrations from 18 – 30 ppmv, NEC recommended 3 layers of catalysts. The SCR manufacturers recommended only 1 layer of catalysts for incinerators. The high costs estimated by NEC for increased catalyst volumes, steel box, steel support, catalyst replacement, and subsequent installation costs and annual operating costs were the results of this approach. There are many types of SCR catalysts, and the optimized volume of catalysts, dimension of SCRs, space velocity or face velocity, and direction of flue gas flow (vertical or horizontal) may vary with each manufacturer and design, however 2-3 layers of catalysts are excessive for SRU/TG incinerators using refinery fuel gas.

Other differences in NEC's estimates and manufacturers design

- On page 24, in the last paragraph of the non-confidential report, the statement "*Note that the SCRs proposed for this application by the SCR vendor was sized for a velocity of about 10 ft/sec for the smaller ones. However, the velocity was about 50 ft/sec for the two larger ones, Facility 6 and 8. It appears there was confusion about the actual flow rate for the larger units.*" is not correct.

  Staff sent the process information (e.g. flow rates in dry standard cubic feet per minute (dscfm) and temperature of the flue gas (degrees F)) to two prominent SCR manufacturers to ask for costs, and the costs provided from both manufacturers were within an order of magnitude. Staff contacted the manufacturers again for confirmation. The manufacturer explained that the flow rates in dscfm were entered into a proprietary computer model along with other data to size the SCR and estimate the volume of catalysts and the number of catalysts layer. In the case of Refinery 6, tempering air was used to cool down the temperature from 1,100 F to 900 F, and the design resulted in one layer of catalysts for 5 and 2 ppmv NOx.

- The costs that NEC estimated for the heat exchangers were $2.6 M - $3.98 M and ammonia storage tank system was $1.5 M. The costs for ammonia injection grid were already included in the SCR costs provided by the SCR manufacturers. The costs for the ammonia tank and heat exchangers were estimated to be $15,000 and $250,000 respectively.

High estimates for new CEMS

NEC estimated $1.5 M for CEMS replacement for each SRU/TG incinerator. Based on information received from the SCAQMD's Technology Advancement Office, CEMS upgrades will be needed to measure 2 ppmv NOx. Upgrades can vary between a change in the existing analyzer range to a full CEMS replacement. The cost estimates for CEMS upgrades that the refineries provided to the SCAQMD on their CEMS applications were highly variable. For example, a refinery cited $270,000 for an analyzer replacement, but other applications showed that they also provided $20,000 - $60,000 estimates for analyzer replacement. A realistic average estimate for an installed replacement analyzer cost is in the range of $20,000 – $60,000 per CEMS range, based on the most prevalent information that the SCAQMD received on CEMS applications.

PWVs using 4.5 factor and including costs for ammonia tanks and heat exchangers

Staff used a factor of 1.86 to estimate the TIC which is consistent with 1) the EPA OAQPS Costs Guidelines and 2) the approach used in the 2005 NOx RECLAIM amendment. Staff then added 50% contingency to cover uncertainty. Thus, the overall factor was 1.86 x 1.5 = 2.79. NEC used a factor of 4.5. The refineries reported that they used a factor of 4 for boilers and heaters. SCRs have not yet been used to reduce NOx emissions from SRU/TG incinerators, thus the actual factor cannot be verified. This factor can vary case-by-case and with the complexity of the refinery it may be reasonable to use 4.5. If staff used a factor of 4.5 for TICs and NEC's estimates for ammonia storage tanks and heat exchangers, the results would be as tabulated in Table H.2 for SCRs and LoTOx. Details are included in Table H.3. The shaded areas in Table H.2 are for units with cost-effectiveness values more than $50,000 per ton. The cumulative totals in Table H.2 do not include costs for Device ID 2413 with cost effectiveness values more than $50,000 per ton.

Table H. 2 – Revised Costs of SCRs and LoTOx Scrubbers for SRU/TGTUs

Fac ID	Dev	SCR			LoTOx		
		AQMD ($M)	Reductions (tpd)	AQMD CE ($/ton)	AQMD ($M)	Reductions (tpd)	AQMD CE ($/ton)
6	D952	16.2	0.05	33,298	22.7	0.05	46,458
5	911/913	11.3	0.05	23,491	18.9	0.05	39,321
5	927/929	11.3	0.03	46,697	18.9	0.03	78,167
5	955/957	11.3	0.07	17,818	18.9	0.07	29,826
1	910	17.3	0.06	34,379	22.7	0.06	45,127
1	2413	16.9	0.03	63,593	22.7	0.03	85,404
8	294	15.2	0.06	25,805	22.7	0.06	38,490
Total for cost-effective units		**82.5**	**0.32**	**28,270**	**105.8**	**0.29**	**39,963**

The PWVs for cost effective units vary from $82.5 – $105.8 M (± 50%). The cost effectiveness values vary from $28,270 - $39,963 per ton. The emission reductions are between 0.29 – 0.32 tons per day.

Conclusions

1. Regarding NEC's approach:

   — The SCR catalysts for FCCUs are not equivalent to the SCR catalysts for SRU/TG incinerators, thus NEC's approach of prorating the costs of FCCU's SCR to incinerator's SCR is not appropriate.

   — NEC's design of 2 to 3 layers of catalysts for SRU/TG incinerators is not consistent with industrial design; and results in high equipment costs, steel costs, catalysts costs, installation costs, and catalyst replacement costs.

   — NEC's estimate for new CEMS is not consistent with previous applications submitted by refineries in RECLAIM.

2. In 2014, staff used a factor of 1.86 to estimate the TIC from total equipment costs in consistent with a) the EPA OAQPS Costs Guidelines and b) the approach that AQMD used in the 2005 NOx RECLAIM amendment. Staff added 50% contingency to cover any uncertainty. NEC used a factor of 4.5. The refineries also reported that they used a factor of 4 for boilers and heaters. If staff had used a factor of 4.5, the results would be as tabulated in Table H.2. The PWVs for cost effective units vary from \$82.5 – \$105.8 M (± 50%). The cost effectiveness values vary from \$28,270 - \$39,963 per ton. The emission reductions are between 0.29 – 0.32 tons per day.

Table H. 3 – SCR Costs for SRU/TGTUs Using Factor of 4.5 for TIC and NEC's Costs for Ammonia Tanks and Heat Exchangers

		SCR	LoTOx	KnowNOx	
	Capital Costs				
	SCR reactor, catalysts, flow modeling, inlet/outlet expansion joints, ammonia flow control skid for 80% control	$461,000			
	Costs for 90% control (5% higher than for 80% control)	$484,050			
	Cost for 95% control (10% higher than for 80% control)	$507,100			
	Ammonia storage	not use			
	Heat exchanger from 750 F - 1100 F (note 3)	not use			
	Equipment costs (EC)	$507,100			
	Total Equipment Costs = TEC = 1.24 EC (note 4)	$628,804			
	Total Installed Costs = 4.5 TEC	$2,829,618			
	Annual Operating Costs				
	Annual costs for aqueous ammonia (note 6)	$82,782			
	Annual operating costs = ammonia costs + miscellaneous	$122,782			
	SCR replacement (note 8)	every 5-yrs			
	Catalysts replacement	$507,100			
	Present Worth Value				
1	Refinery 6 , D952 - 2011 emissions (lbs/year)	41,066	41,066	41,066	
	Control efficiency	95%	95%	95%	
	2011 emission reduction (tpd)	0.05	0.05	0.05	
	SCR installed	2,829,618			note 1
	Ammonia tank + heat exchanger	4,800,000			note 2
	PWV = Capital +(15.62*Annual) + (2.52*Cat Replacement)	10,825,365	15,103,805	5,129,299	note 1
	PWV ($) with 1.5 contingency factor	16,238,047	22,655,708	7,693,949	
	Cost effectiveness ($/ton)	**33,298**	**46,458**	**15,777**	
2	Refinery 1, D910 - 2011 emissions (lbs/year)	42,273	42,273	42,273	
	Control efficiency	95%	95%	95%	
	2011 emission reduction (tpd)	0.06	0.06	0.06	
	SCR installed	2,829,618			note 1
	Ammonia tank + heat exchanger	5,480,000			note 2
	PWV = Capital +(15.62*Annual) + (2.52*Cat Replacement)	11,505,365	15,102,381	5,147,338	note 1
	PWV ($) with 1.5 contingency factor	17,258,047	22,653,571	7,721,008	
	Cost effectiveness ($/ton)	**34,379**	**45,127**	**15,381**	
3	Refinery 1, D2413 - 2011 emissions (lbs/year)	22,337	22,337	22,337	
	Control efficiency	95%	95%	95%	
	2011 emission reduction (tpd)	0.03	0.03	0.03	
	SCR installed	2,829,618			note 1
	Ammonia tank + heat exchanger	5,220,000			note 2
	PWV = Capital +(15.62*Annual) + (2.52*Cat Replacement)	11,245,365	15,102,381	5,147,338	note 1
	PWV ($) with 1.5 contingency factor	16,868,047	22,653,571	7,721,008	
	Cost effectiveness ($/ton)	**63,593**	**85,404**	**29,108**	

		SCR	LoTOx	KnowNOx	
4	Refinery 8, D294 - 2011 emissions (lbs/year)	49,563	49,563	49,563	
	Control efficiency	95%	95%	95%	
	2011 emission reduction (tpd)	0.06	0.06	0.06	
	SCR installed	2,829,618			note 1
	Ammonia tank + heat exchanger	4,100,000			note 2
	PWV = Capital +(15.62*Annual) + (2.52*Cat Replacement)	10,125,365	15,102,381	5,147,338	note 1
	PWV ($) with 1.5 contingency factor	15,188,047	22,653,571	7,721,008	
	Cost effectiveness ($/ton)	**25,805**	**38,490**	**13,118**	
5	Refinery 5, D955 and D957 - 2011 emissions (lbs/year)	53,348	53,348	53,348	
	Control efficiency	95%	95%	95%	
	2011 emission reduction (tpd)	0.07	0.07	0.07	
	SCR installed	2,829,618			note 1
	Ammonia tank + heat exchanger	1,500,000			note 2
	PWV = Capital +(15.62*Annual) + (2.52*Cat Replacement)	7,525,365	12,596,810	6,495,659	note 1
	PWV ($) with 1.5 contingency factor	11,288,047	18,895,215	9,743,489	
	Cost effectiveness ($/ton)	**17,818**	**29,826**	**15,380**	
6	Refinery 5, D927 and D929 - 2011 emissions (lbs/year)	20,356	20,356	20,356	
	Control efficiency	95%	95%	95%	
	2011 emission reduction (tpd)	0.03	0.03	0.03	
	SCR installed	2,829,618			note 1
	Ammonia tank + heat exchanger	1,500,000			note 2
	PWV = Capital +(15.62*Annual) + (2.52*Cat Replacement)	7,525,365	12,596,810	6,495,659	note 1
	PWV ($) with 1.5 contingency factor	11,288,047	18,895,215	9,743,489	
	Cost effectiveness ($/ton)	**46,697**	**78,167**	**40,308**	
7	Refinery 5, D911 and D913 - 2011 emissions (lbs/year)	40,466	40,466	40,466	
	Control efficiency	95%	95%	95%	
	2011 emission reduction (tpd)	0.05	0.05	0.05	
	SCR installed	2,829,618			note 1
	Ammonia tank + heat exchanger	1,500,000			note 2
	PWV = Capital +(15.62*Annual) + (2.52*Cat Replacement)	7,525,365	12,596,810	6,495,659	note 1
	PWV ($) with 1.5 contingency factor	11,288,047	18,895,215	9,743,489	
	Cost effectiveness ($/ton)	**23,491**	**39,321**	**20,276**	
	Notes: 1) Estimates with 4.5 factor, 2) Use NEC's estimates foe ammonia tanks and heat exchangers				

Appendix I – Review of NEC's Analysis for Coke Calciner

The purpose of this review is to analyze NEC's approach, explain the differences in the estimates compared to staff's analysis, and provide recommendations to reconcile the numbers if possible.

Summary of Staff's Approach

Cost data for all feasible control technologies including LoTOx and UltraCat system. Staff sent the process information to the manufacturers, and the manufacturers provided equipment costs, annual operating costs, and foot print of the control devices. Staff used the approach in the EPA OAQPS Guidelines to estimate the Total Installed Costs (TIC = 1.86 x Equipment Costs.) This approach was used in the staff report of the 2005 RECLAIM rule amendment. Costs were increased by 50% to cover any uncertainty in the estimated TIC and annual operating costs.

Summary of NEC's Approach

NEC proposed 5 – 10 ppmv for BARCT. NEC used the costs provided to staff, and applied a factor of 4.67 to cover uncertainty in process development and installation costs. As a result, TIC = 4.67 x Equipment costs. NEC estimated annual operating costs and PWVs. NEC felt that Ultra-Cat was not a solution for the coke calciner.

Staff's Review and Conclusions

Staff was in agreement with NEC that the coke calciner is a challenging application, and perhaps the BARCT level should be set at 5 ppmv as recommended by the consultant. Staff was in agreement with NEC that a factor higher than the EPA OAQPS's factor of 1.86 would be reasonable for the coke calciner because of the space congestion situation at the site. After extensive discussion, staff however felt that NEC's knowledge about Ultra-Cat was limited at this stage. In addition, staff revised the calculation and used a factor of 4.5 instead of 1.86 for both LoTOx and Ultra-Cat technologies. The revised PWVs and cost effectiveness results are tabulated below.

Table I. 1 – Revised SCR Costs for Coke Calciner Estimated Using a Factor of 4.5 for TIC

	Staff's revised estimates based on 4.5 factor				NEC
	Belco 2 ppmv	Trimer 97%	**Belco 5 ppmv**	**Trimer 92%**	estimates
BARCT level	2 ppmv	97% control	**5 ppmv**	**92% control**	5 - 10 ppmv
Increment emission reductions (tpd)	0.24	0.24	**0.21**	**0.21**	0.17-0.21
PWVs ± 50% ($ M)	$54.94	$91.17	**$54.29**	**$91.17**	$39.50
Cost-Effectiveness ($/ton)	$25,361	$19,295	**$28,661**	**$20,561**	$21K-$25K

Appendix J – Review of NEC's Analysis for Gas Turbines

Staff has no comments on NEC's review on gas turbines.

Appendix K – Co-Benefits of Energy Efficiency Projects

Table K.1 below summarizes information on NOx reductions that are expected to occur as co-benefits of energy efficiency projects undertaken by the refineries in the Basin from the California Air Resources Board (CARB)'s report "Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources – Refinery Sector Public Report, June 6, 2013.

CARB approved the Energy Efficiency and Co-Benefit Assessment of Large Industrial Facilities (EEA Regulation) on July 22, 2010. The regulation required the largest industrial sources in California to conduct a one-time assessment of fuel and energy consumption, and emissions of greenhouse gas, criteria pollutants, and toxic air contaminants. Affected facilities were also required to identify potential improvements in equipment, processes, or systems that could result in energy savings. http://www.arb.ca.gov/cc/energyaudits/energyaudits.htm#background.

CARB has a three-phase implementation plan to implement the EEA Regulation. Phase 1 was to develop the industrial sector public reports. From June 2013 to April 2015, CARB released five separate public reports compiling the information provided by the facilities subject to the EEA Regulation. The first report released in June 2013 was for the refinery sector. CARB is working on Phase 2 to develop the findings report, and Phase 3 to develop the Energy Efficiency Implementation Program. http://www.arb.ca.gov/cc/energyaudits/publicreports.htm.

CARB staff indicated that currently there was no requirement for the refineries to report the emissions stated in the public report released in June 2013 for inventory purposes. In addition, CARB had no process by which the inventory could be modified based on the estimates provided in the report. CARB did not know if the actual emission reductions would be different from the estimates in the report, and CARB had no plan to count these estimates as reductions to the current air quality. Thus, staff did not count the reductions in this proposal.

Table K. 1- Summary of Emission Reductions and Schedules of Energy Efficiency Projects

Facility	Completed/Ongoing Projects Completed Before 2011 (tpd)			Scheduled Projects After 2011 (tpd)	Under Investigation Projects After 2011 (tpd)		**Total (tpd)**	
	Range		Completion Date		Range		**Range**	
BP-Carson (Table II-4)	0.064	0.064	2009-11	0.014	0.019	0.019	**0.097**	**0.097**
Chevron El Segundo (Table II-9)	0.054	0.088	2007-11	0	0	0	**0.054**	**0.088**
Phillips66 Carson (Table II-17)	0	0.026	2008-11	0	0	0.013	**0**	**0.039**
Phillips66 Wilmington (Table II-21)	0	0	2009-11	0	0	0.013	**0**	**0.013**
ExxonMobil Torrance (Table II-29)	0.204	0.204	2008-11	0.036	0	0	**0.24**	**0.24**
Tesoro Los Angeles (Table II-37)	0.221	0.221	2009-11	0	0.049	0.049	**0.27**	**0.27**
Valero Wilmington (Table II-46)	0.056	0.056	2007-10	0	0	0	**0.056**	**0.056**
TOTAL (tpd)	0.6	0.7		0.1	0.1	0.1	**0.7**	**0.8**

Reference: Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources - Refinery Sector Public Report, June 6,

Note:

BP Carson identified 21 projects completed in the 2009-11 time frame (p.35)

Chevron identified 27 projects completed in the 2007-11 time frame (p. 38)

Phillips66 Carson identified 8 projects completed in the 2008-11 time frame (p. 44)

Phillips66 Wilmington identified 7 projects completed in the 2009-11 time frame that reduced 0 tpd NOx (p. 47)

ExxonMobil identified 25 projects completed in the 2008-2011 time frame (p.53)

Tesoro identified 11 projects completed in 2009-11 time frame (p.59)

Valero identified 13 projects completed in 2007-2010 time frame (p.65)

Appendix L – Survey Questionnaires for Refinery Sector

In June 2013, staff developed Survey Questionnaire to collect pertinent information for the NOx RECLAIM rule development. The Survey Questionnaire was sent to the 37 top emitting facilities and California Portland Cement Company which was the #1 NOx emission source in the Basin in 2008. The Survey Questionnaire for the refinery sector and the non-refinery sector are shown below.

South Coast Air Quality Management
2013 NOx RECLAIM
Survey Questionnaire for Refineries
(Due Date: July 12, 2013)

Facility Contact

1. Please provide the facility contact for this project:
   Name: ________________________________
   Title: ________________________________
   Phone Number: _________________________
   Email Address: _________________________

Top NOx Emitting Equipment or Processes

(* The attached list may contain the information requested)

2. * Please verify the attached list for the top 10 NOx emitting equipment and processes at your facility in Compliance Year 2011 and their emissions.

3. Please mark on the attached list the NOx control equipment installed **<u>after the 2005 NOx RECLAIM amendment</u>**

Boilers, Heaters, Furnaces, Kilns, Turbines, and Cogeneration Units (Major and Large Sources)

4. For each major and large combustion source at your facility, please verify the following information in the attached list, and provide information if the attached list does not contain this specific information:
   a. * Device description, Device ID, Process Name
   b. * Emissions in CY 2011 (tons per day)
   c. * Maximum unit rating (MMBTU/hr)
   d. * Type of fuel used
   e. Fuel usage rate and BTU content of fuel
   f. Flue gas flow rate (million dry standard cubic feet), temperature, oxygen and water content
   g. Representative flue gas analysis and fuel gas analysis

   h. NOx concentration in the exhaust flue gas (ppmv at 3% O_2 or ppmv at 15% O_2). Please attach a copy of the most current source test reports/results.
   i. Allowable back pressure
   j. * Control technology used (e.g. LNB, SCR, NOx scrubber)

5. For the control technology identified in item #4 above:
   a. Device description, Device ID
   b. Manufacturer's name and performance. Please attach a copy of manufacturer's specification/guarantee
   c. Design parameters (e.g. maximum flue gas flow rate, inlet and outlet ppmv, ammonia slip)
   d. If the control device is shared between multiple NOx emitting sources, please identify all other sources that are vented to this control device
   e. Dimension of the add-on NOx control device (e.g. length, width, height of the SCR, catalyst volume)
   f. Cost information (capital costs, installation costs, and annual operating costs)
   g. Installation date (e.g. July 2005)

6. Provide drawings that show location and distances between the major and large NOx sources at the facility.

Fluid Catalytic Cracking Units

7. If the facility currently uses NOx reduction catalysts, please provide:
   a. Manufacturer's name
   b. Usage rate (e.g. lbs of catalysts added per day)
   c. Flue gas flow rate, temperature, oxygen, water content and flue gas analysis
   d. NOx in the exhaust flue gas (ppmv at 3% O2). Please attach a copy of the source test results
   e. Cost information (annual operating costs)

8. If the facility uses add-on NOx control device, please provide:
   a. Manufacturer's name and performance. Please attach a copy of manufacturer's specification/guarantee
   b. Design parameters (max flue gas flow rate, temperature, oxygen, water content, flue gas analysis)
   c. NOx in the exhaust flue gas (ppmv at 3% O2). Please attach a copy of the source test report/results
   d. Dimension of the add-on NOx control device
   e. Cost information (capital costs, installation costs, and annual operating costs)
   f. Installation date (e.g. July 2005)

Reports Submitted Under the U.S. EPA Consent Decree

9. If the facility must install control technology to reduce the NOx emissions under an U.S. Environmental Protection Agency (EPA)'s consent decree, please provide the District a copy of the most recent reports/test results submitted to the EPA related to this consent decree.

Feasible Control Approach Including Energy Efficiency Project

10. List any feasible control approach that your facility plans to install, including replacement of the existing units with higher energy efficient units, to further reduce your facility's NOx emissions and green-house gases. Provide a brief description of the control approach, manufacturer's name, estimated emission reductions, and cost information.

If you have any questions, please contact either: Minh Pham, P.E. (909) 396-2613, mpham@aqmd.gov, or Gary Quinn, P.E. (909) 396-3121, gquinn@aqmd.gov

Please submit information via e-mail by July 12, 2013
to Minh Pham and Gary Quinn.
Thank you for participating in the Survey.

Part II – BARCT Analyses for Non-Refinery Sector

Part II contains the information related to the BARCT analyses for the non-refinery sector. Part II includes 7 Appendices from Appendix M to Appendix S that discuss 1) the NOx control technologies, 2) costs and cost effectiveness analyses for the NOx emitting sources at the top 27 non-refinery facilities, and 3) staff's review of the consultant's costs and cost effectiveness analyses. The Survey Questionnaires for non-refinery facilities are included in Appendix T.

Appendix M – Cement Kilns

Process Description

In the NOx RECLAIM program there is one facility that operates cement kilns. This facility, under normal operation, has typically been among the highest NOx emitters in the RECLAIM program. This facility produces gray cement from limestone, sand, shale, and clay raw materials. The raw materials are processed into a mix that is fed into a long, dry kiln that goes through pyroprocessing. Pyroprocessing transforms the fine raw mix into cement clinker through physical and chemical reactions inside the kiln. The facility operates two of these long, dry kilns that rotate slowly and are inclined at an angle. The raw materials are fed at the higher end of the kiln and proceed through it under the high heat of the combustion gases that are produced by the kiln burners at the lower end. Once the material exits the kiln, it is considered clinker and is cooled, and further processed (ground, milled) into cement. The combustion fuels used in these kilns include petroleum coke, natural gas and tire-derived fuel (TDF). The flue gases exiting the kilns are then ducted to individual waste heat boilers that operate a steam generator for electricity. After the waste heat boilers, the flue gases from each kiln go to a dedicated baghouse which separates the solid particulate. The resultant flue gases then exit from individual stacks.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged from the 2000 (Tier 1) Level, which is 2.73 pounds of NOx per ton of clinker produced.

Current Emission Inventory

There are two long, dry cement kilns located at the subject NOx RECLAIM facility. This facility was not in operation in compliance year 2011 due to decreased production and has not been in operation since. Therefore, for the purposes of calculating the BARCT reductions, the baseline emissions from the 2012 AQMP base year (2008) were used for the emission reduction determination and cost effectiveness calculation.

Table M. 1 - 2011 Emissions for Cement Kilns

Equipment Type (at Top 37 Facilities)	Number of Units	2008 Emissions (tpd)
Long, Dry Cement Kiln	2	1.61

Control Technology

Long, dry cement kilns have achieved NOx reductions to the 2000 (Tier 1) level by utilizing low NOx burners and mid kiln firing with tire-derived fuel (TDF). With TDF, whole tires are introduced at an inlet location about midway along the kiln's calcining zone. TDF lowers NOx emissions by lowering the flame temperatures and reducing thermal NOx with the introduction of a slower burning fuel.

The facility began testing one of the kilns with a selective non-catalytic reduction system (SNCR) before it ceased operation. This approach involves injecting ammonia directly into the kiln heating zone, where NOx reduction occurs without the utilization of a catalyst. With SNCR, the temperature window is critical for successful treatment of NOx. With a long, dry cement kiln, this is often difficult to achieve with the different temperature zones along its length and the necessity to inject the reagent mid-kiln. NOx treatment is easier to achieve on more modern preheater/precalcining kilns with SNCR since they are often shorter in length and the temperature window lies towards the exit of the kiln at the lower part of the preheater tower. This allows for readily feasible reagent introduction. The testing of the SNCR system at the facility yielded about a 30% NOx reduction. As applied to other kilns, SNCR is capable of achieving between a 30 and 50% NOx reduction. In the case of this facility, a 45% NOx reduction would result in meeting the New Source Performance Standard (NSPS) level of 1.5 pounds of NOx per ton of clinker produced. This emission level is equivalent to that of a new precalciner kiln using SNCR for NOx control.

After discussions with several vendors, there is more than one technology available for effective treatment of NOx from this source category beyond the Tier 1 level. To effectively achieve the most significant NOx reduction, selective catalytic reduction (SCR) is a proven technology that is well suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F. In cement applications, the inherently high particulate load of the flue gas stream has created problems in the past for catalysts. The dust can plug the catalyst matrix openings and can also mask active sites which results in a degradation of performance. This obstacle can be overcome by utilizing sootblowers which blow off the accumulated particulates at timed intervals from the catalyst surface. There have been several installations of SCR systems on cement kilns in Europe that can handle high dust loads in the flue gas. The installation at Monselice, Italy has been in operation since 2006 and the installation at Mergelstetten has been in operation since 2010. An SCR has also been installed on a long, dry kiln in Joppa, Illinois. It has been operating since 2013 and can achieve an 80% NOx reduction.

For cement applications, an alternate technology is available primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. The flue gas is injected with ammonia that mixes with the gas and permeates across the ceramic filter wall. The filter material is embedded with catalyst which removes the NOx. Dry sorbent is injected in the flue gas to react with SOx. The resultant particulate, along with other particulate matter is captured at the outside of the filter walls.

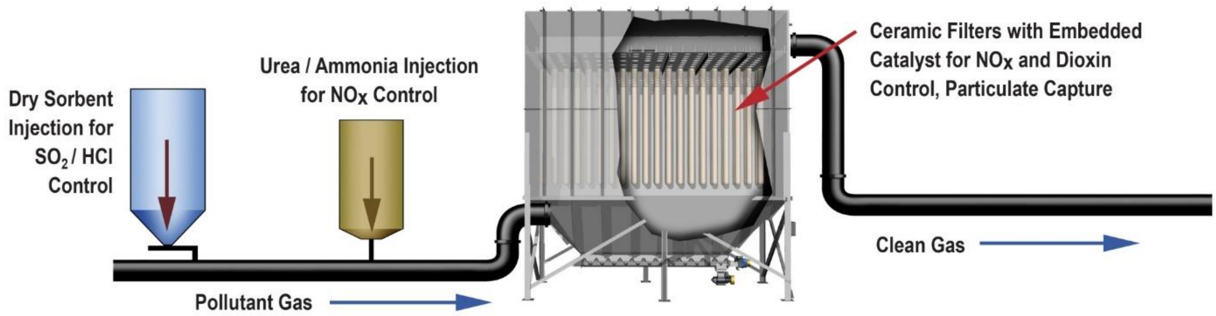

Figure M. 1 - Ultra Cat Ceramic Filter System

The accumulated solids on the filters are removed by a pulsed jet of air through the filter and the resultant solid waste is collected underneath the housing and is landfilled. This technology is guaranteed to achieve an 80% NOx reduction.

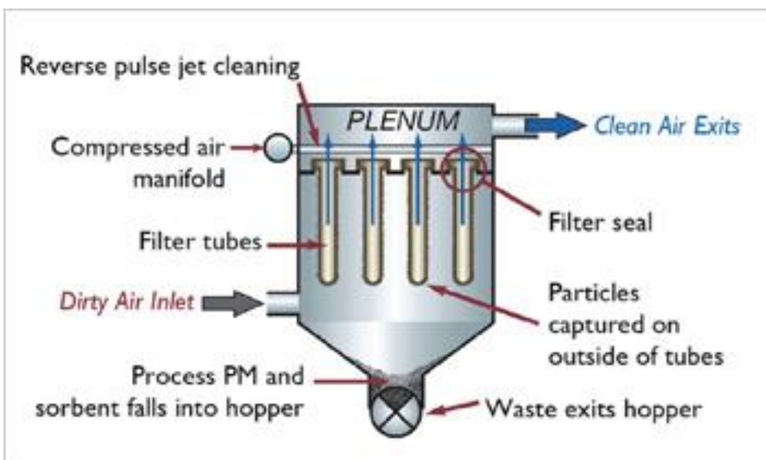

Figure M. 2 - Close-Up of Filter Housing and System Operation

Another multi-pollutant control option for cement kilns is also possible that would reduce SOx and PM with a wet gas scrubber and treat NOx with SCR. A wet gas scrubber uses a liquid solution, typically caustic, as the absorbing agent for SO_2. The absorbed SO_2 is converted to sulfates and sulfites which are then captured in the liquid effluent treatment system where they are separated and then disposed. Solid particulates in the flue gas stream are removed by impaction with the liquid droplets inside the scrubber. The outlet flue gas stream is then processed by the SCR system for removal of NOx. Temperature control is extremely important for proper functioning of the pollutant control systems, primarily for SCR. The gas has to be hot enough after being processed by the scrubber for SCR treatment. This can be achieved by utilizing a heat exchanger ahead of the scrubber to reheat the gas to the proper temperature for SCR treatment. In this configuration, the scrubbing unit is installed ahead of the SCR for the purposes of removing SO_2 and preventing the formation of ammonium bisulfate (ABS). ABS formation is a result of sulfur compounds reacting with ammonia from the SCR system at a lower temperature below the dew point. ABS formation is reversible, and this involves heating the catalyst to evaporate it. When SO_2 is present in the flue gas stream, the minimum SCR process temperature is determined by the formation of ABS. With the removal of SO_2 from the flue gas stream by the scrubber, however, ABS formation is not an issue when operating the SCR system at the lower end of the normal temperature range.

Proposed BARCT level and Emission Reductions

SCAQMD command and control Rule 1112 set NOx limits for gray cement kilns. Last amended in 1986, the rule limits NOx emissions to 6.4 pounds per ton of clinker produced, averaged over any 30 consecutive day period. The 2005 NOx RECLAIM amendment proposed no new BARCT for cement kilns, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for cement kilns is 2.73 pounds of NOx per ton of clinker produced. When they were in operation, the two units in the NOx RECLAIM universe of facilities were compliant with the Tier 1 NOx emission level.

Based on vendor discussions, the proposed BARCT level for gray cement kilns is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system. This would result in an emission level of about 0.5 pounds of NOx per ton of clinker produced.

The emission reductions achieved from the two long, dry cement kilns, based on the 2008 compliance year baseline emissions, amount to 1.29 tons per day. This is the incremental reduction from the Tier 1 emission level.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs.

For an SCR installation on both kilns, the equipment costs include the SCR equipment, ductwork, steel, electrical, ammonia skid, sootblower air compressors, and insulation. The SCR system includes two layers of catalyst with a third layer for standby. A contingency value of 60% of the SCR equipment costs was estimated for the foundation civil work and other contingency. The SCR system for each kiln would be installed after the existing waste heat boiler and before the existing baghouse. This facility has specific plot space considerations that would require the installation of the SCR system between 5 and 30 yards from each waste heat boiler, depending on the kiln. The equipment would be placed on elevated platforms to allow for vehicle and/or railcar traffic underneath. There is no expected heat loss from the insulated ductwork. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were assigned a three year replacement interval.

For the Ultra Cat ceramic filter system, the equipment costs for both kilns include the emission control system, ammonia skid, booster fan, and engineering services, along with the installation. The annual operating costs include ammonia consumption, dry sorbent consumption, power consumption, labor, waste disposal, replacement filter costs. Since this facility is also a SOx source, dry sorbent injection for SOx removal will be required. This system would replace the existing baghouses at this facility.

The vendor-based equipment costs for the wet scrubber with heat exchanger and SCR for each kiln include the costs for the heat exchanger systems (ductwork, housing, dust collection hoppers), wet gas scrubber systems (venturi scrubber, pumps, structural steel, piping), and the SCR systems (2 layers of catalyst for each kiln, ductwork, ammonia skid, programmable logic control, sootblowers).

A contingency value of 60% of the equipment costs was estimated for the foundation and civil work, installation, and other contingency. The annual operating costs include ammonia consumption, catalyst replacement (3 year), caustic consumption, exhaust system fan power, scrubber pump power, and SCR dilution air fan and sootblower power. This system would replace the existing baghouses at this facility.

For all the scenarios, a present worth value (PWV) was calculated for the cement kilns using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This approach in calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table M. 2 - Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.			
Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
	Vendor 1	**Vendor 2**	**Vendor 3**
Capital Costs ($)	14,950,000	30,000,000	31,938,838
Annual Costs ($)	1,220,500	1,000,000	4,818,537
Present Worth Value ($)	34,016,651	45,622,000	107,214,017
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	2,897	3,885	9,130
LCF Cost Effectiveness ($/ton)	4,635	6,216	14,609

To achieve an 80% NOx reduction, the cost effectiveness for cement kilns ranges from $2,900/ton to $9,100/ton ($4,600/ton to $14,600/ton, using LCF). Since the facility is also a SOx source, the calculated cost effectiveness combining NOx and SOx reductions equates to $3,300/ton for Vendor 2 and $7,600/ton for Vendor 3. This assumes a SOx reduction of 0.25 tons per day, as stated for the SOx RECLAIM amendment of 2010. All of the scenarios using the aforementioned NOx reduction technologies for flue gas treatment of cement kilns are considered cost effective.

Review of ETS's Analysis for Cement Kilns

ETS, Inc. was commissioned by SCAQMD to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted a site visit at the facility to verify site specific considerations for the installation of control equipment.

For all the vendor installation estimates, a project scope contingency of 15% was applied to the total direct and indirect capital costs.

ETS concurs that there is sufficient plot space to install the control equipment for all three vendors and that an 80% NOx emission reduction is both feasible and cost effective.

Table M. 3 - ETS Revisions to Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.			
Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
	Vendor 1	**Vendor 2**	**Vendor 3**
	SCAQMD (ETS)	SCAQMD (ETS)	SCAQMD (ETS)
Capital Costs ($)	14,950,000 (17,192,500)	30,000,000 (34,500,000)	31,938,838 (36,729,664)
Annual Costs ($)*	1,220,500	1,000,000	4,818,537
Present Worth Value ($)	34,016,651 (36,259,151)	45,622,000 (50,122,000)	107,214,017 (112,004,843)
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	2,897 (3,088)	3,885 (4,268)	9,130 (9,538)
LCF Cost Effectiveness ($/ton)	4,635 (4,941)	6,216 (6,829)	14,609 (15,262)

* No revisions made by ETS

The facility made several comments regarding the BARCT analysis and SCAQMD staff conducted further research that resulted in a refinement of the cost analysis. Further communications with Vendor 1 revealed that the original estimate capital costs should have been doubled, as the previous costs were clarified as being for only one kiln. The facility had a concern over the temperatures at the exit of the waste heat boiler, before entering the control equipment. The facility provided an updated temperature which was 100 degrees below what had been provided previously and was below the normal operating temperature for normal SCR operation. To address this change, additional costs for reheating the flue gas were incorporated into the estimate, along with the natural gas costs to fuel the added duct burner. This updated system would utilize a natural gas-fired duct burner with a heat exchanger to reheat the gas approximately 100-150 degrees to enable the SCR catalyst to operate normally. The project contingency and other contingencies were adjusted to reflect the updated costs. The capital and operational costs for reheating the flue gas were applied to all three vendor estimates. In addition, operational costs were incorporated into the Vendor 3 estimate for wastewater treatment of the wet gas scrubber effluent. Furthermore, costs for powering new induced draft (ID) fans were also incorporated into the vendor estimates.

Table M. 4 - SCAQMD Revisions to Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.			
Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
	Vendor 1	**Vendor 2**	**Vendor 3**
	ETS (SCAQMD)	ETS (SCAQMD)	ETS (SCAQMD)
Capital Costs ($)	17,192,500 (37,812,000)	34,500,000 (38,400,000)	36,729,664 (42,166,606)
Annual Costs ($)*	1,220,500 (2,029,048)	1,000,000 (1,430,116)	4,818,537 (5,722,253)
Present Worth Value ($)	36,259,151 (69,509,788)	50,122,000 (60,741,272)	112,004,843 (151,559,636)
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	3,088 (5,919)	4,268 (5,172)	9,538 (11,203)
LCF Cost Effectiveness ($/ton)	4,941 (9,471)	6,829 (8,276)	15,262 (17,927)

To achieve the proposed BARCT level, the revised cost effectiveness for cement kilns ranges from $5,200/ton to $11,200/ton ($8,300/ton to $17,900/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of cement kilns are considered feasible and cost effective.

References for Cement Kilns

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Appendix N – Container Glass Melting Furnaces

Process Description

In the NOx RECLAIM program there is one facility among the top 37 NOx emitting facilities that operates container glass melting furnaces. This facility produces container glass from dry, solid raw materials that are melted in the furnaces and then formed into glass container bottles.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which is 1.2 pounds of NOx per ton of glass pulled.

Current Emission Inventory

There are two glass melting furnaces located at the subject NOx RECLAIM facility.

Table N. 1 - 2011 Emissions for Container Glass Melting Furnaces

Equipment Type	Number of Units	2011 Emissions (tpd)
Glass Melting Furnace (Container Glass)	2	0.30

Control Technology

Glass melting furnaces can achieve NOx reductions to the 2000 (Tier 1) level by utilizing oxy fuel firing. With oxy fuel firing, pure oxygen is used as the combustion reactant instead of nitrogen-laden ambient air. A higher temperature can be achieved for the batch melt based on the higher combustion efficiency in addition to achieving lower NOx emissions.

There is more than one technology available for effective treatment of NOx from this source category. To effectively achieve a significant NOx reduction, selective catalytic reduction (SCR) is a proven technology that is well suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

For glass melting applications, an alternate technology is available that has been achieved in practice, primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. Please refer to Appendix M for further details. This technology is guaranteed to achieve an 80% NOx reduction and has been installed or is under construction at 12 glass manufacturing locations worldwide.

Proposed BARCT level and Emission Reductions

SCAQMD command and control Rule 1117 set NOx limits for glass melting furnaces. Last amended in 1984, the rule limits NOx emissions to 4.0 pounds per ton of glass pulled, effective in 1992. The 2005 NOx RECLAIM amendment proposed no new BARCT for container glass melting furnaces, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for container glass melting furnaces is 1.2 pounds of NOx per ton of glass pulled. The two units in the NOx RECLAIM universe are currently compliant with the Tier 1 emission level.
Based on vendor discussions, the proposed BARCT level for container glass melting furnaces is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system. This would result in a NOx emission rate of 0.24 pounds per ton of glass pulled.

The emission reductions achieved from the two container glass melting furnaces, based on the reported value of emissions, amount to 0.24 tons per day. This is the incremental reduction from the Tier 1 emission level of 1.2 pounds of NOx per ton of glass pulled.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs and the costs provided by the facility.

For the Ultra Cat ceramic filter system, the equipment costs were scaled from an existing vendor-based installation quotation for a sodium silicate glass melting furnace. The equipment costs which include the emission control system, ammonia skid, and booster fan were scaled by the heat input rate to the 0.6 power based on general chemical engineering cost estimating practice. The installation costs were calculated to be 40% of the equipment costs. The cost of installation as well as the cost of engineering services was scaled by the heat input rate. The annual operating costs (also scaled by heat input rate) include ammonia consumption, dry sorbent consumption, power consumption, labor, waste disposal, replacement filter costs. Since this facility is also a SOx source, dry sorbent injection for SOx removal will be required. This system would replace the existing dry scrubbing system and electrostatic precipitators (ESPs) at this facility.

For an SCR installation, two scenarios were considered. In the first scenario, one SCR chamber would handle the exhaust streams from the three ESPs. At this facility, three ESPs handle the exhaust from the two glass melting furnaces in which one ESP is operated as a backup. In the second scenario, one SCR would handle the exhaust from each ESP, so there would be a total of three SCR systems installed.

The vendor-based costs for the first option include the engineering, fabrication and field installation of a single SCR chamber sized to handle the exhaust from both furnaces. The SCR system includes one layer of catalyst with extra space for a second layer, supporting structure, ammonia skid, and programmable logic control (PLC) system. A contingency value of 80% of the SCR equipment costs was estimated for the foundation and ductwork to and from the existing stacks. This facility has specific plot space considerations that would require the installation of the SCR system roughly 30 yards from the ESPs and roughly 15 yards back to the stacks. The equipment would be placed on an elevated platform above the existing rail line. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were conservatively assigned an annual replacement interval. In addition, a 20% contingency was added to the annual costs for freight and installation.

The vendor-based costs for the second option include the engineering, fabrication and field installation of three SCR chambers as described for the first option, each sized to handle the exhaust from one furnace. A contingency value of 150% of the SCR equipment costs was estimated for the foundation and ductwork to and from the existing stacks. The annual operating costs were also derived as described for the first option. This option also included an additional 20% contingency.

The facility also provided an estimate for the retrofitting of one furnace that was based on the EPA cost manual for SCR installations for NOx removal. To expand this singular case to address the remaining furnace, two scenarios were considered for this approach. The first option would include the installation of two SCR systems, each sized to handle the exhaust of one furnace, manifolded to the existing three ESPs. The second option would include the installation of three SCR systems, each sized to handle the exhaust of one furnace. Each SCR would handle the exhaust from each ESP. For each option, the costs for additional SCRs were calculated by multiplying the facility-provided costs for a single unit with number of additional units required for each of the two options. Also for each option, a 15% contingency factor was applied to the direct and indirect costs. The annual operating costs for each option include operations and maintenance labor/materials, ammonia consumption, power consumptions and catalyst costs. In addition, an indirect annual cost factor was added and was calculated to be the capital costs multiplied by the capital recovery factor (CRF) for a 25 year installation at a 4% interest rate.

For all the scenarios, a present worth value (PWV) was calculated for the glass melting furnaces using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This approach in calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

Cost Effectiveness = PWV / (ER x 365 x 25 years)

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

LCF Cost Effectiveness = (TIC x CRF) + AC / (ER x 365),

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table N. 2 - Cost Effectiveness for Container Glass Melting Furnaces

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.					
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.					
Vendor 3: SCR system installed post ESP using costs provided by facility per EPA cost Manual. NOx removal only. Option 1: two chambers. Option 2: three chambers.					
	Vendor 1	**Vendor 2 Option 1**	**Vendor 2 Option 2**	**Vendor 3 Option 1**	**Vendor 3 Option 2**
Capital Costs ($)	5,134,891	2,070,000	5,000,000	4,096,959	6,145,439
Annual Costs ($)	567,686	132,500	180,750	560,123	840,185
Present Worth Value ($)	14,003,287	4,139,195	7,823,677	12,847,207	19,270,811
Emission reductions (tpd)	0.24	0.24	0.24	0.24	0.24
DCF Cost Effectiveness ($/ton)	6,442	1,904	3,599	5,910	8,865
LCF Cost Effectiveness ($/ton)	10,308	3,047	5,759	9,457	14,186

To achieve an 80% reduction, the cost effectiveness for container glass melting furnace ranges from \$1,900/ton to \$8,900/ton (\$3,000/ton to \$14,200/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of container glass melting furnaces are considered cost effective.

Review of ETS's Analysis for Container Glass Melting Furnaces

ETS, Inc. was commissioned by SCAQMD to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted a site visit at the facility to verify site specific considerations for the installation of control equipment.

For the Vendor 1 estimates, the calculation of the installation costs were adjusted to reflect 40% of the equipment costs, instead of being scaled from the base equipment case. Additionally, a contingency of 15% of the capital costs was applied to the overall estimate.

The Vendor 2 estimates were also adjusted by ETS for several items. Foundation and ductwork costs were added, as well as costs for new stacks for both options (single and three SCRs). Operation and labor costs were added to the annual costs for both options as well as costs for power consumption with the addition of a booster fan. The annual catalyst replacement costs were also adjusted for both options to reflect labor costs to replace the catalyst, along with recycling/disposal costs for spent catalyst. Additionally, a contingency of 15% of the capital costs was applied to the overall estimate.
The Vendor 3 cost estimates were not evaluated by ETS because they felt that the cost estimates provided by the equipment vendors with actual field experience with NOx removal would provide better estimates than the EPA cost manual method. Also, there was a disparity in the costs with the vendor estimates versus the EPA cost manual method because economics of scale were not taken into consideration, such as volume cost savings for multiple pieces of equipment.

Since the glass melting furnaces at this facility are also SOx emission sources, the flue gas has to be at a sufficiently high temperature to prevent ammonium bisulfate formation (ABS) while also removing NOx emissions effectively. ABS forms when the SO_3 in the flue gas reacts with the ammonia in the SCR system to produce ammonium salts. If the flue gas temperature is above the dew point for ABS, it will remain in the gaseous phase. However, if the temperature of the flue gas falls below the dew point for ABS, it will precipitate and deposit as a sticky substance on the SCR catalyst matrix. The result is reduced activity of the SCR catalyst and it will need to be reheated to reverse the process and reactivate it. Upon speaking with the equipment vendors, the SOx emissions from the glass melting furnaces would not result in ABS formation as long as the flue gas temperature remains as high as possible, any heat loss from the ductwork is mitigated, and there is not an overly lengthy duct run constructed to the SCR. The current stack temperatures at the facility are adequately above the ABS dew point and, therefore, there is no foreseeable issue with ABS deposition on the SCR catalyst.

ETS concurs that the NOx emission levels that are achievable is 80% for this source category. Achieving this level would be feasible with both technologies evaluated (i.e., ceramic filtration system or SCR). The plot considerations at this facility are complex, leaving little room for the installation of control equipment. The Vendor 1 system would involve removing the existing SOx dry scrubbers to create additional space and would need to be tied in presumably under a facility shutdown period. The Vendor 2 system would be complex as well, but ETS concurs that there is sufficient plot space for the installation of SCR.

To achieve the proposed BARCT level, the revised cost effectiveness for container glass melting furnaces ranges from $3,000/ton to $8,900/ton ($4,700/ton to $14,200/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of container glass melting furnaces are considered feasible and cost effective.

Table N. 3 - ETS Revisions to Cost Effectiveness for Container Glass Melting Furnaces

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.					
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.					
Vendor 3: SCR system installed post ESP using costs provided by facility per EPA cost manual. NOx removal only. Option 1: two chambers. Option 2: three chambers.					
	Vendor 1	**Vendor 2 Option 1**	**Vendor 2 Option 2**	**Vendor 3 Option 1**	**Vendor 3 Option 2**
	SCAQMD (ETS)	SCAQMD (ETS)	SCAQMD (ETS)	SCAQMD*	SCAQMD*
Capital Costs ($)	5,134,891 (5,684,463)	2,070,000 (2,685,250)	5,000,000 (5,405,000)	4,096,959	6,145,439
Annual Costs ($)	567,686*	132,500 (240,909)	180,750 (360,753)	560,123	840,185
Present Worth Value ($)	14,003,287 (14,522,859)	4,139,195 (6,448,737)	7,823,677 (11,040,686)	12,847,207	19,270,811
Emission reductions (tpd)	0.24	0.24	0.24	0.24	0.24
DCF Cost Effectiveness ($/ton)	6,442 (6,695)	1,904 (2,967)	3,599 (5,079)	5,910	8,865
LCF Cost Effectiveness ($/ton)	10,308 (10,713)	3,047 (4,747)	5,759 (8,127)	9,457	14,186

*No revisions were made by ETS to the Vendor 3 costing or the indicated fields

References for Container Glass Melting Furnaces

1. *Alternative Control Techniques Document – NOx Emissions from Glass Manufacturing.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. June 1994; EPA-453/R-94-037.

2. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda item 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

3. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

4. *Ammonium Bisulphate Inhibition of SCR Catalysts*. Thogersen, J.; Slabiak, T.; White, N. Haldor Topsoe.

5. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

6. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

Appendix O– Sodium Silicate Furnace

Process Description

In the NOx RECLAIM program there is only one facility that produces sodium silicate. Sodium silicate is a substance either in a solid or liquid form that has a variety of industrial uses. It is manufactured by heating soda ash and sand in a melting furnace. The materials react with heat to produce sodium silicate and carbon dioxide.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which is 6.4 pounds of NOx per ton of glass pulled. This unit is considered a glass melting furnace, but since it processes sodium silicate, it is different than other types of glass melting furnaces such as container glass, flat glass, etc.

Current Emission Inventory

The single source sodium silicate melting furnace is a NOx major source.

Table O. 1 - 2011 Emissions for Sodium Silicate Furnace

Equipment Type	Number of Units	2011 Emissions (tpd)
Sodium Silicate Furnace	1	0.11

Control Technology

The raw material batch feed is delivered into the melting furnace which is fired by several natural gas-fired burners that melt the process feed. The flue gas then exits the furnace via a stack into the atmosphere. Combustion technology can often be employed to achieve some NOx reductions. Blower air staging, for example, can lower the temperature and result in lowering NOx emissions by around 15 to 20%.

To effectively achieve the largest reduction, however, selective catalytic reduction (SCR) is the technology that is best suited for significant flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

For glass melting applications, an alternate technology is available that has been achieved in practice, primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. Please refer to Appendix M for further descriptions. This technology is guaranteed to achieve an 80% NOx reduction.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1117 set limits for glass melting furnaces. Last amended in 1984, the rule limits NOx emissions to 4.0 pounds per ton of glass pulled, effective in 1992. The 2005 NOx RECLAIM amendment proposed no new BARCT for sodium silicate furnaces or other glass melting furnaces, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for sodium silicate furnaces is 6.4 pounds per ton of glass pulled.

The single unit in the NOx RECLAIM universe is currently compliant with the Tier 1 emission level. For sodium silicate furnaces based on vendor discussions, the proposed BARCT level for this source category is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system.

The emission reductions achieved from the sodium silicate furnace, based on the reported value of emissions, amounts to 0.09 tons per day. This is the incremental reduction from the Tier 1 emission level and is almost equivalent to the Tier 1 emission level for container glass melting furnaces (1.2 lbs/ton of glass pulled).

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs. There are no site-specific conditions that would increase the installation costs dramatically.

For SCR, the equipment and installation costs include the SCR chamber, one layer of catalyst with extra space for a second layer, supporting structure, ammonia skid, programmable logic control system (PLC), and engineering/fabrication. The foundation and ductwork was estimated to be 60% of the equipment and installation costs. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were conservatively assigned an annual replacement interval. In addition, a 20% contingency was added to the annual costs for freight and installation.

For the Ultra Cat ceramic filter system, the equipment costs include the emission control system, ammonia skid, booster fan, and engineering services. The installation costs were calculated to be 40% of the equipment costs. The annual operating costs include ammonia consumption, power consumption, labor, waste disposal and replacement filter costs. Since this facility is not a SOx source, dry sorbent injection for SOx removal would not be required.
For both technologies, a present worth value (PWV) was calculated for the sodium silicate furnace using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each technology using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table O. 2 - Cost Effectiveness for Sodium Silicate Furnace

Control Technology	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
SCR	1,600,000	76,315	2,792,193	0.09	3,470
Ultra Cat	1,986,161	166,016	4,579,663	0.09	5,691

The cost effectiveness for the sodium silicate furnace ranges from $3,500/ton to $5,700/ton ($5,600/ton to $9,100/ton, using LCF). This is to achieve an 80% NOx reduction. Both technologies for reducing NOx for the sodium silicate furnace are considered cost effective.

Review of ETS's Analysis for Sodium Silicate Furnace

ETS, Inc. was commissioned by SCAQMD to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted an evaluation of the control technology and the costs for the installation of the control equipment.

For both vendor estimates, a contingency of 15% was applied the total direct and indirect capital costs. For the Vendor 2 estimate, the capital costs pertinent to SO_2 treatment were removed since this system would be removing NOx only.

To achieve the proposed BARCT level, the revised cost effectiveness for the sodium silicate furnace ranges from $3,800/ton to $5,700/ton ($6,000/ton to $9,200/ton, using LCF). Both scenarios using the aforementioned NOx reduction technologies for flue gas treatment of the sodium silicate furnace are considered feasible and cost effective.

Table O. 3 - ETS Revisions to Cost Effectiveness for Sodium Silicate Furnace

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.		
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.		
	Vendor 1	**Vendor 2**
	SCAQMD (ETS)	SCAQMD (ETS)
Capital Costs ($)	1,600,000 (1,840,000)	1,986,161 (2,009,243)
Annual Costs ($)*	76,315	166,016
Present Worth Value ($)	2,792,193 (3,032,193)	4,579,663 (4,602,745)
Emission reductions (tpd)	0.09	0.09
DCF Cost Effectiveness ($/ton)	3,470 (3,768)	5,691 (5,719)
LCF Cost Effectiveness ($/ton)	5,552 (6,029)	9,106 (9,152)

*No revisions were made by ETS

References for Sodium Silicate Furnace

1. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

3. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

Appendix P – Metal Heat Treating Furnaces >150 MMBTU/hr

Process Description

In the NOx RECLAIM program there is one facility that operates these furnaces among the top 37 facilities. For the 2005 NOx RECLAIM amendment, a BARCT level of 45 ppm (0.055 lb/MMBTU) was established for metal heat treating furnaces.

Current Emission Inventory

Among the top 37 facilities in the NOx RECLAIM program, there are two furnaces above 150 MMBTU/hr that are metal heat treating furnaces for processing steel.

Table P. 1 - 2011 Emissions for Metal Heat Treating Furnaces >150 MMBTU/hr

Equipment Type (at Top 37 Facilities)	Number of Units	2011 Emissions (tpd)
Furnace >150 MMBTU/hr	2	0.49

Control Technology

As with all combustion sources, the type of burner used can affect the emissions. Some burners are lower NOx emitting than others. But for these types of furnaces, there are often dozens of burners that cumulatively require a high heat input. To achieve higher efficiency and to consume less fuel, recuperative and regenerative burners are used. These burners employ the principle of using preheated inlet air which is heated by the exhaust gases for more efficient combustion.

To effectively achieve a significant NOx reduction, however, selective catalytic reduction (SCR) is the technology that is best suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1147 set limits for metal heat treating furnaces at 60 ppm at 3% O_2 (0.073 lb/MMBTU). This rule was adopted in 2008 to address NOx emissions from miscellaneous sources. The 2005 NOx RECLAIM amendment proposed a BARCT level of 45 ppm at 3% O_2 (0.055 lb/MMBTU).

Based on vendor discussions for furnaces above 150 MMBTU/hr, the proposed BARCT level for this source category is an 80% reduction and the control technology to achieve the NOx reductions is SCR. An 80% NOx reduction from the 2005 BARCT level is equivalent to 9 ppm at 3% O_2.

The 2011 emissions adjusted to the 2005 BARCT level amount to 0.70 tons per day. The incremental reductions from each furnace from the2005 BARCT level to the proposed BARCT level are 0.28 tons per day. One of the furnaces is already operating with an SCR system and is currently achieving around 20 ppm NOx. The source category incremental emission reductions achieved from the metal heat treating furnaces above 150 MMBTU/hr from the 2005 BARCT level amount to 0.56 tons per day.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs and the costs from an existing installation.

For SCR, the vendor-based equipment and installation costs include the SCR catalyst, reactor and ductwork, ammonia skid, dilution air fan, civil work, and installation. A contingency value of 200% of the SCR equipment costs was used to estimate the installation, foundation, civil work, and other construction uncertainties. The annual operating costs include ammonia consumption, catalyst replacement costs (2 year replacement interval), power consumption, and maintenance.

The existing equipment-based equipment costs include installation, SCR catalyst system, ammonia skid, and control system. A 60% contingency value of the equipment and installation cost was used to estimate the costs for other ductwork. The annual operating costs include ammonia consumption, catalyst replacement costs (2 year replacement interval), and maintenance.

For both scenario cases, a present worth value (PWV) was calculated for the metal heat treating furnaces using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

Cost Effectiveness = PWV / (ER x 365 x 25 years)

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

LCF Cost Effectiveness = (TIC x CRF) + AC / (ER x 365),

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table P. 2 - Cost Effectiveness for Furnaces > 150 MMBTU/hr

Control Technology	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
Vendor-based	2,800,152	440,631	9,683,684	0.28	3,800
Existing equipment-based	3,732,800	255,600	7,725,783	0.28	3,000

The cost effectiveness for furnaces above 150 MMBTU/hr ranges from $3,000/ton to $3,800/ton ($4,800/ton to $6,100/ton, using LCF). Achieving an 80% NOx reduction, SCR technology applied for reducing NOx for these furnaces is considered cost effective.

Review of ETS's Analysis for Metal Heat Treating Furnaces >150 MMBTU/hr

ETS, Inc. was commissioned by SCAQMD to provide an independent evaluation of the previously described BARCT and cost analysis. Based on SCAQMD's analysis and the review of technical information, ETS concurs that the NOx reduction level that can be achieved with SCR technology is 80%. No changes to the cost estimates were made.

References for Metal Heat Treating Furnaces >150 MMBTU/hr

1. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

Appendix Q – Non-Refinery, Non-Power Plant Stationary Gas Turbines

Process Description

In the RECLAIM program, stationary gas turbines are used primarily to drive compressors or to generate power. In command and control, Rule 1134 limits the NOx emissions for all gaseous and liquid-fueled engines that are above 0.3 MW. Gas turbines operate either in simple cycle or combined cycle. Simple cycle units use the mechanical energy of shaft work that is transferred to and used by a gas compressor, for example, or to run an electrical generator to produce electricity. A combined cycle unit adds an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Combined cycle units are more efficient due to their use of two work cycles from the same shaft operation. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are not power plant turbines (turbines that produce solely electric utility power). Some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam. In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which equates to 0.06 lb/MMBTU.

Current Emission Inventory

Among the top thirty seven non-power plant NOx emitting facilities in the RECLAIM universe, there are twenty gas turbines that are either major or large source units. Four of these units are currently utilizing some level of NOx control with selective catalytic reduction (SCR). The OCS turbines, which are fired on diesel or process gas, have the highest NOx emission concentrations in this source category. Six of these units are operated on an offshore oil drilling platform (outer continental shelf, or OCS).

Table Q. 1 - 2011 Emissions for RECLAIM Non-Power Plant Gas Turbines

Turbine Type	Number of Units	2011 Emissions (tpd)
Total	20	1.92
Gas Compression	7	0.59
Cogeneration	6	0.75
Power Generation	1	0.09
OCS	6	0.49

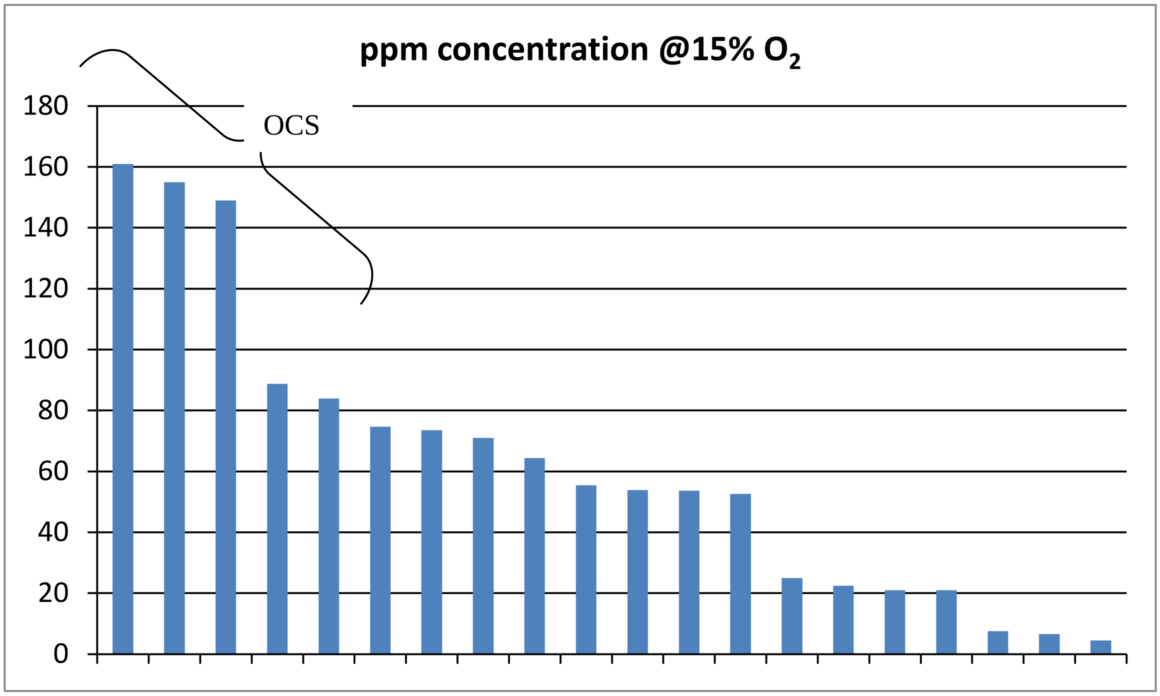

Figure Q. 1 - NOx Concentrations for Non-Power Plant Gas Turbines at Top 37 Emitting Facilities

Control Technology

An uncontrolled unit will typically be emitting well over 100 ppm of NOx. There are several methods of NOx control for gas turbines, with differing levels of reduction.

Steam or water injection involves the introduction of either medium into the combustor flame zone to lower the flame temperature, thus reducing NOx formation. Typically, this will reduce NOx emissions up to 60%. Dry low emissions (DLE or DLN) is a type of dry control which involves a major modification to the turbine's combustion system. Unlike diffusion flames where the fuel and air mixes and combusts at the same time, DLE combustors are premixed, where the air and fuel mix first and then are combusted to produce a lower flame temperature. In addition, these systems operate under lean conditions, often with dual staged-combustion, further lowering NOx emissions. DLE technology can achieve NOx levels between around 10 and 45 ppm.

Selective catalytic reduction (SCR) is the most effective technology that can achieve ultra low NOx emissions. The technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1134 set limits for gas turbines for a range of sizes (ratings), with the limits varying between 9 and 25 ppm, corrected to 15% oxygen content. The 2005 NOx RECLAIM amendment proposed no new BARCT for gas turbines, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for natural gas and diesel fueled gas turbines in equivalent to 0.06 lb/MMBTU, which corresponds to approximately 17 ppm at 15% O_2. This reference limit can be higher, depending on the efficiency of the unit. The majority of the RECLAIM units in this source category have not installed the controls to meet the Tier 1 emission level.

For the non-power plant, non-refinery gas turbines in the top 37 facilities and based on vendor discussions and achieved in practice BACT installations, the proposed BARCT level for this source category is 2 ppm @15% O_2.and the control technology to achieve the NOx reductions is SCR. For units that are emitting less than 40 ppm NOx at 15% O2, a 2 ppm emission level is achievable with SCR only. In Figure 1, this would apply to the 7 units to the right of the chart. However, for those units emitting at 40 ppm, a 95 percent reduction is achievable. For the remainder of these units, a 95% reduction would achieve around 3 to 4 ppm. The power generating offshore units would achieve 8 ppm at a 95% reduction for their current emission level since they have the highest emissions. The offshore gas compression turbines can achieve 5 ppm at a 95% reduction. A 2 ppm level would be achievable for the units emitting above 40 ppm if these units would install either wet or dry combustion controls to comply with the Tier 1 emission level. The single power generating gas turbine that is non-OCS currently operates with an SCR system permitted at 5 ppm for NOx. Staff believes that a replacement of the catalyst system would be sufficient to meet the 2 ppm BARCT level. As a worst case, a present worth value was calculated from the same curve derived from existing refinery power generating units for a complete replacement of the SCR catalyst and equipment.

The emission reductions achieved from both subsets of units emitting above and below 40 ppm in the non-OCS sector are 1.04 tons per day. This is the incremental reduction from the Tier 1 level. The OCS units would add an additional 0.07 tons per day.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs. The vendor-supplied costs were for the SCR equipment only. This consists of the SCR housing, SCR catalyst, mixing ductwork, ammonia injection skid, PLC system, and CFD flow modeling.

Installation costs can vary due to the type of facility and any site-specific limitations. To derive a reasonable estimate, the installation costs were calculated to be double (or 200%) of the equipment costs. Since an SCR installation at an offshore facility could be more complicated than a typical onshore installation, the installation costs were calculated at four times the equipment costs to account for the unique site considerations for this type of installation. The annual operating costs include catalyst replacement (replacement interval of three years), ammonia consumption (19%), and electrical consumption.

A present worth value (PWV) was then calculated for each gas turbine using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each gas turbine using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

The cost effectiveness for non-power plant, non-OCS gas turbines ranges from $4,700/ton to $35,900/ton ($7,500/ton to $57,500/ton, using LCF). This is to achieve a 95% reduction for those units emitting higher than 40 ppm and to achieve 2 ppm for those emitting lower than 40 ppm. For these gas turbines, the installation of SCR to treat NOx is cost effective. If the units emitting above 40 ppm install either wet or dry combustion controls to meet the Tier 1 emission level, then meeting 2 ppm is achievable.

The cost effectiveness for the offshore gas turbines ranges from $51,400/ton to $59,200/ton ($82,300/ton to $94,700/ton, using LCF). These figures reflect the power generating units achieving 8 ppm and the gas compression units meeting 5 ppm with SCR only. Since the cost effectiveness is above $50,000/ton and based on past rule makings, the OCS gas turbines are not considered cost effective in achieving the incremental NOx BARCT reductions from the Tier 1 level.

Table Q. 2 - Cost Effectiveness for Non-Power Plant Gas Turbines

Unit	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
1	2,786,139	707,847	13,844,125	0.081	18,716
2	2,858,592	687,666	13,601,308	0.085	17,537
3	2,780,064	727,308	14,142,076	0.084	18,518
4	2,583,085	297,613	7,232,403	0.015	52,748
5	2,604,485	352,643	8,113,472	0.015	59,174
6	2,608,400	329,730	7,759,450	0.015	56,592
7	2,252,960	68,133	3,317,340	0.007	51,422
8	2,259,305	75,832	3,443,960	0.007	53,384
9	2,269,455	68,955	3,346,666	0.007	51,876
10	1,517,898	68,321	2,585,211	0.009	33,250
11	1,519,272	65,261	2,538,781	0.008	35,916
12	1,531,680	69,149	2,611,931	0.009	33,594
13	1,516,755	63,256	2,509,164	0.008	35,497
14	2,320,584	437,781	9,159,602	0.156	6,478
15	1,443,846	80,740	2,705,163	0.025	11,658
16	1,442,694	92,373	2,885,744	0.016	19,823
17	2,765,694	555,222	11,439,367	0.269	4,666
18	2,438,727	389,347	8,521,114	0.128	7,310
19	2,432,730	397,575	8,643,648	0.135	7,019
20	*	*	13,597,600	0.060	24,979

*PWV was determined from cost curve for refinery gas turbines (Figure C-5)

Review of ETS's Analysis for Metal Heat Treating Furnaces Above 150 MMBTU/hr

ETS, Inc. was commissioned by SCAQMD to provide an independent evaluation of the previously described BARCT and cost analysis. ETS concurs with the costing information and the conservative approach taken for calculating the costs for the possibly varied installations, given the site-specific aspects. ETS also concurs with the achievability of the reductions using SCR technology and no changes to the cost estimates were made.

References for Non-Refinery, Non-Power Plant Stationary Gas Turbines

1. *Best Available Retrofit Control Technology Assessment – TXI Riverside Cement.* SCAQMD, August 8, 2008.

2. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

3. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

4. *Combustion and Fuels*. Solar Turbines Incorporated Presentation, Luke Cowell, June 6, 2012.

5. *Catalog of CHP Technologies: Combustion Turbines*. United States Environmental Protection Agency - Combined Heat and Power Partnership, March 2015.

6. *Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. January 1993; EPA-453/R-93-007.

7. *AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors*. United States Environmental Protection Agency, January 1995.

Appendix R – Non-Refinery Stationary Internal Combustion Engines

Process Description

Stationary Internal Combustion Engines (ICEs) are used primarily to drive pumps, compressors, or to generate power. In command and control, Rule 1110.2 limits the NOx emissions for all gaseous and liquid-fueled engines that are above 50 brake horsepower (bhp). There are generally two types of engines, spark-ignited (SI) or compression ignited (CI) engines. SI engines ignite the air/fuel mixture with a spark while CI engines use the heat of compression to ignite the fuel that is injected into the combustion chamber.

Engines can run at either stoichiometrically rich or lean conditions, depending on the air to fuel ratio. Rich combustion corresponds to an air /fuel ratio that is fuel-rich while lean combustion corresponds to a fuel-lean air/fuel ratio. Small SI engines typically run as rich burn, but many larger units as well as CI engines operate under lean conditions. Usually, more air is inducted than is required for complete combustion and the resultant exhaust oxygen level is high (over 5%). Rich burn engines typically operate very close to stoichiometric conditions by drawing only the necessary air to combust the fuel. Spark-ignited engines are typically fired on gaseous fuels such as natural gas, while compression-ignited engines are fired on liquid fuels such as diesel.

In 2005, there was no new BARCT proposed for this source category. Consequently, the emission factor has remained unchanged since 2000 (Tier 1), which equates to about 57 ppm at 15% O_2 for natural gas-fired engines. During the 2008 amendment of Rule 1110.2, most stationary ICEs outside of RECLAIM (with the exception of biogas engines) were required to meet a NOx emission limit of 11 ppm at 15% O_2 by July 1, 2011.

Current Emission Inventory

Among the top thirty seven NOx emitting facilities in the RECLAIM universe, there are thirty one engines that are either major or large source units. Nine of these units are controlled with NSCR (non-selective catalytic reduction) as these engines are rich burn. Sixteen of these engines are SI lean burn units, while the remaining six are CI lean burn units. The CI lean burn units are all operated on an offshore oil drilling platform (outer continental shelf, or OCS). Six of the SI lean burn units are two-stroke engines (See Table 1). The engine sizes range from a little over 700 bhp to 5,500 bhp.

Table R. 1 - 2011 Emissions for Internal Combustion Engines at Top 37 Facilities

Engine Type (at Top 37 Facilities)	Number of engines	2011 emissions (tpd)
Total	37	0.56
Lean Burn (Spark-Ignited)	16	0.34
Lean Burn (Compression Ignited), OCS	6	0.03
Rich Burn (Spark-Ignited)	9	0.02
Power Plant (2 stroke)	6	0.18

There are also 6 additional ICEs that belong to a power producing facility, and the combined emissions from these engines were 0.18 tons per day in 2011. These engines are 2-stroke engines that are fired on diesel fuel due to the lack of access to natural gas.

CI engines, which are fired on diesel, have the highest NOx emission concentrations in this source category. 2-stroke SI engines have higher NOx emissions than 4-stroke SI engines since the higher efficiencies in 2-stroke engines translate to a hotter combustion temperature that can create more NOx.

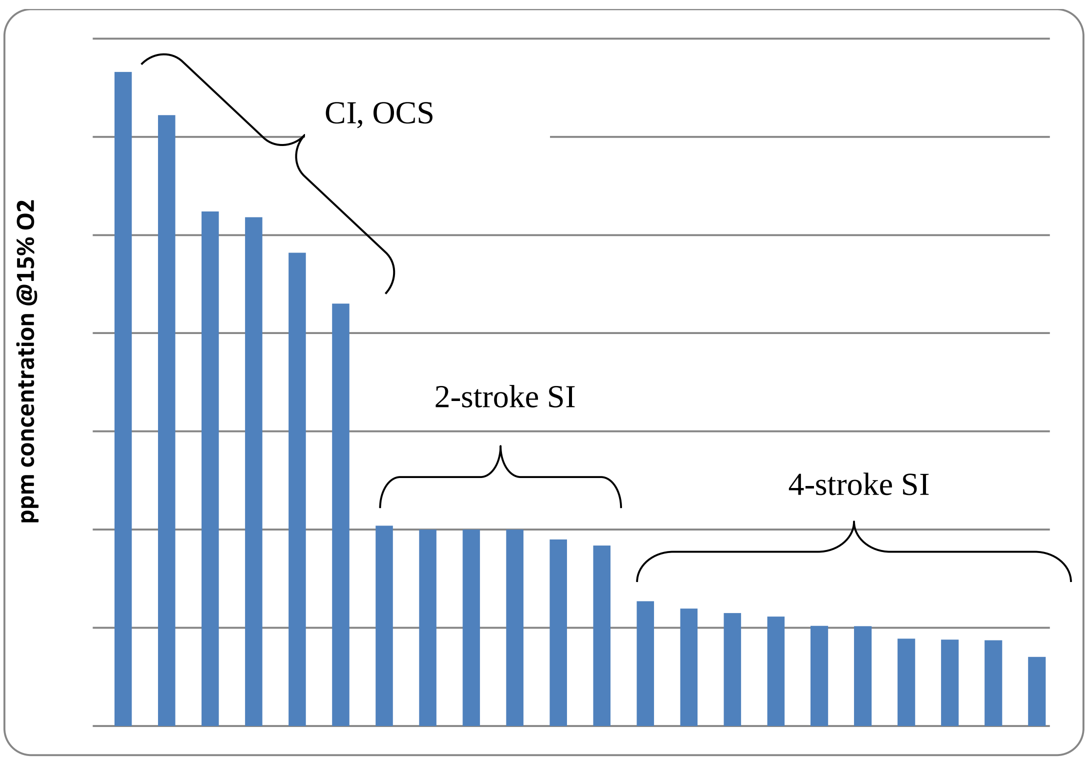

Figure R. 1 - NOx concentrations for Lean Burn ICEs at Top 37 Emitting Facilities

Control Technology

The flue gas from rich burn engines is typically very low in excess oxygen. This enables NOx reduction to take place via Non-Selective Catalytic Reduction technology (NSCR), which is inexpensive, readily installed, and simultaneously removes NOx, CO, and VOC. NSCR (or three-way) catalysts have been commercially available for many years and can achieve NOx removal efficiencies of over 90 percent. The catalyst reduces NOx to nitrogen and oxygen in the presence of CO and VOC, while simultaneously oxidizing CO and VOC to form carbon dioxide and water. Precise air/fuel ratio control is required since the catalytic reactions must occur within a narrow air/fuel ratio band.

With lean burn exhaust the higher oxygen content does not allow effective removal of NOx with NSCR. On this basis, CO and VOC will have a preferential reaction with the oxygen instead of the NOx. In this case, Selective Catalytic Reduction (SCR) is the technology of choice. Oxygen is an essential ingredient in the SCR reactions and the excess oxygen in the exhaust gas provides this. Ammonia (or urea) is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of a catalyst to produce nitrogen and water vapor. The catalyst material is typically a base metal catalyst such as titanium dioxide or vanadium pentoxide, and operates within a temperature range of 450 to 850 F.

Proposed BARCT level and Emission Reductions

The 2008 amendment to Rule 1110.2 established a NOx emission level of 11 ppm @15% O_2 for most IC engines. The technology identified for rich burn engines was NSCR while the technology identified for lean burn engines was SCR. The effective date for complying with the final rule limit has been in effect for over four years. NSCR is feasible for rich burn engines and SCR is feasible for both two-stroke and four-stroke lean-burn engines.

The 2005 RECLAIM amendment proposed no new BARCT for IC engines, so these units have been only required to meet the Year 2000 Tier 1 emission level. For the non-power plant engines in the top 37 emitting facilities, the proposed BARCT level is 11 ppm @15% O_2. The rich burn engines in this category have all been retrofitted with NSCR and most of them meet the proposed BARCT level. These three way catalysts were installed to control CO and VOC for compliance with Rule 1110.2 requirements by July 1, 2011, since these pollutants are not governed under RECLAIM rules. There is an added benefit with three way catalysts because they also control NOx and this has resulted in emission reductions for these engines. For lean burn engines, however, the control technology to achieve the NOx reductions is SCR. If all the non-OCS engines in this category were to achieve the proposed BARCT level, the emission reductions from the Tier 1 level would be 0.84 tons per day. There is a portion of this reduction that is attributed to the rich burn engines and it amounts to 0.07 ton per day. Recent source tests indicate that the majority of these engines are already meeting the proposed

BARCT level of 11 ppm. It is assumed that these engines will continue to meet the 11 ppm emission level.

The power plant engines, since they are 2-stroke diesel engines, are more difficult in terms of reducing NOx emissions. These engines are isolated and there is no other fuel backup. The unique nature of these engines provides a challenge with regards to very low allowable backpressures, which makes SCR an inflexible treatment option. Therefore, there is no new proposed BARCT for power plant ICEs.

The OCS engines in this category will not be subject to the new BARCT because the engines at offshore platforms run rig generators that are often variable in load. SCR systems need a more constant load so that the proper operating temperatures can be sustained for effective NOx removal.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using both vendor-supplied costs along with installation costs from an existing SCR installation on a lean-burn engine. The vendor-supplied costs were for the SCR equipment only. This consists of the SCR housing, SCR catalyst, mixing ductwork, expansion joint, urea injection skid (control system, pump, dosing unit), and an air compression/drying system.

Installation costs can vary due to the type of facility and any site-specific limitations. To derive a reasonable estimate, the costs from an achieved in practice SCR installation on a lean-burning engine were used. This engine is located at Orange County Sanitation District (OCSD), is fired on natural gas and digester gas, and is retrofitted with an oxidation catalyst and SCR. It was installed in 2009 and has been consistently been meeting the 11 ppm NOx limit of Rule 1110.2. The catalyst system had to be placed on an externally constructed platform because of the site constraints inside the engine building. These additional costs have been included as part of this analysis in anticipation of any supplemental support structures necessary to accommodate the SCR system. The 2009 dollar figures for the OCSD installation were raised to 2013 dollar values using the Marshall & Swift Index inflation factor. The installation costs for all the affected engines were scaled by horsepower based on the costs for this installation at OCSD.

The annual operating costs include catalyst replacement, reagent consumption, reagent delivery system maintenance, and electrical consumption. The annual costs for the OCSD installation assume a 3 year SCR catalyst replacement interval and were scaled for the engines in this source category by engine horsepower. For two-stroke engines, a very conservative replacement interval of one year was selected due to the potentially more contaminated exhaust gas stream (ash, soot) from this type of engine.

A present worth value (PWV) was then calculated for each engine using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each engine using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table R. 2 - Cost Effectiveness for Lean-Burn, Non-OCS ICEs

Unit	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
1	890,182	36,625	1,462,338	0.036	4,500
2	890,182	36,625	1,462,338	0.033	4,900
3	890,182	36,625	1,462,338	0.033	4,800
4	890,182	36,625	1,462,338	0.034	4,700
5	890,182	36,625	1,462,338	0.035	4,600
6	1,386,291	82,640	2,677,289	0.043	6,900
7	485,628	25,696	887,048	0.019	5,000
8	485,628	25,696	887,048	0.019	5,000
9	1,307,772	77,475	2,518,084	0.038	7,300
10	485,628	25,696	887,048	0.019	5,100
11	1,307,772	77,475	2,518,084	0.037	7,500
12	2,319,249	100,719	3,892,680	0.084	5,000
13	2,319,249	100,719	3,892,680	0.084	5,000
14	2,319,249	100,719	3,892,680	0.085	5,000
15	2,319,249	100,719	3,892,680	0.083	5,200
16	2,319,249	100,719	3,892,680	0.084	5,000

The cost effectiveness for non-power plant IC engines ranges from $4,500/ton to $7,500/ton ($7,200/ton to $12,000/ton, using LCF). For these engines, the installation of SCR to treat NOx is cost effective.

Review of ETS's Analysis for Non-Refinery Stationary Internal Combustion Engines

ETS, Inc. was commissioned by SCAQMD to provide an independent evaluation of the previously described BARCT and cost analysis. ETS concurs with the costing information and the conservative approach taken for calculating the costs for the possibly varied installations, given the site-specific aspects. ETS also concurs with the achievability of the reductions using SCR technology and no changes to the cost estimates were made.

References for Non-Refinery Stationary Internal Combustion Engines

1. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

3. *AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors*. United States Environmental Protection Agency, January 1995.

4. *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. January 1993; EPA-453/R-93-032.

5. *Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology*. SCAQMD Contract #10114, Orange County Sanitation District, July 2011.

Appendix S – Non-Refinery Boilers >40 MMBTU/hr

In the top 37 emitting facilities, there are four boilers that are above 40 MMBTU/hr. They range between 49 and 247.3 MMBTU/hr. The 2005 BARCT level for these units was 9 ppm at 3% O_2. The incremental NOx reduction going from 9 ppm to a proposed BARCT level of 2 ppm would be 0.01 tons per day.

SCR would be the technology of choice for achieving NOx reductions for larger boilers. The costs for retrofitting these units were estimated from the ETS-adjusted vendor quotes for a similar sized installation for the sodium silicate furnace. The present worth value for the installation in on a 56.6 MMBTU/hr combustion furnace is $4,602,745. The present worth value for the largest unit was calculated from the cost curve developed for refinery boilers and heaters (Figure B-3).

The DCF cost effectiveness for all of the four units were calculated to be above $150,000 per ton of NOx. Therefore, retrofitting with SCR would not be cost effective. ETS concurs that the costs for installing SCR would not be cost effective for this source category.

Table S. 1 - Cost Effectiveness for Non-Refinery Boilers >40 MMBTU/hr

Unit	Rating (MMBTU/hr)	PWV ($)	Incremental Emission Reductions (tpd)	DCF Cost Effectiveness ($/ton)
1	57	4,602,745	0.003	182,107
2	62.5	4,602,745	0.003	153,938
3	49	4,602,745	0.0001	6,447,425
4	247.3	13,527,310	0.004	380,515

Appendix T – Survey Questionnaires for Non-Refinery Sector

South Coast Air Quality Management
2013 NOx RECLAIM
Survey Questionnaire for Non-Refineries
(Due Date: July 12, 2013)

Facility Contact

1. Please provide the facility contact for this project:
   Name: ________________________________
   Title: ________________________________
   Phone Number: _________________________
   Email Address: _________________________

Top NOx Emitting Equipment or Processes
(* The attached list may contain the information requested)

2. * Please verify the attached list for the top 10 NOx emitting equipment and processes at your facility in Compliance Year 2011 and their emissions.

3. Please mark on the attached list the NOx control equipment installed **after the 2005 NOx RECLAIM amendment**

Boilers, Heaters, Furnaces, Kilns, Turbines, and Cogeneration Units (Major and Large Sources)

4. For each major and large combustion source at your facility, please verify the following information in the attached list, and provide information if the attached list does not contain this specific information:
   k. * Device description, Device ID, Process Name
   l. * Emissions in CY 2011 (tons per day)
   m. * Maximum unit rating (MMBTU/hr)
   n. * Type of fuel used
   o. Fuel usage rate and BTU content of fuel
   p. Flue gas flow rate (million dry standard cubic feet), temperature, oxygen and water content
   q. Representative flue gas analysis and fuel gas analysis
   r. NOx concentration in the exhaust flue gas (ppmv at 3% O_2 or ppmv at 15% O_2). Please attach a copy of the most current source test reports/results.
   s. Allowable back pressure
   t. * Control technology used (e.g. LNB, SCR, NOx scrubber)

5. For the control technology identified in item #4 above:
   h. Device description, Device ID

- i. Manufacturer's name and performance. Please attach a copy of manufacturer's specification/guarantee
- j. Design parameters (e.g. maximum flue gas flow rate, inlet and outlet ppmv, ammonia slip)
- k. If the control device is shared between multiple NOx emitting sources, please identify all other sources that are vented to this control device
- l. Dimension of the add-on NOx control device (e.g. length, width, height of the SCR, catalyst volume)
- m. Cost information (capital costs, installation costs, and annual operating costs)
- n. Installation date (e.g. July 2005)

6. Provide drawings that show location and distances between the major and large NOx sources at the facility.

Reports Submitted Under the U.S. EPA Consent Decree

7. If the facility must install control technology to reduce the NOx emissions under an U.S. Environmental Protection Agency (EPA)'s consent decree, please provide the District a copy of the most recent reports/test results submitted to the EPA related to this consent decree.

Feasible Control Approach Including Energy Efficiency Project

8. List any feasible control approach that your facility plans to install, including replacement of the existing units with higher energy efficient units, to further reduce your facility's NOx emissions and green-house gases. Provide a brief description of the control approach, manufacturer's name, estimated emission reductions, and cost information.

If you have any questions, please contact either: Kevin Orellana (909) 396-3492, korellana@aqmd.gov, or Gary Quinn, P.E. (909) 396-3121, gquinn@aqmd.gov

Please submit information via e-mail by July 12, 2013
to Kevin Orellana and Gary Quinn.
Thank you for participating in the Survey.

Part III – RTC Reduction Approaches

Part III contains information pertinent to the RTC reductions estimation. Part III contains three appendices: Appendix U contains a discussion on staff's approaches and calculation to determine the RTC reductions based on the 2015 BARCT levels assessed in Part I for the refinery sector and Part II for the non-refinery sector. Staff's calculation were also based on the 2011 audited NOx emissions for all NOx RECLAIM facilities except power plants. For power plants, staff used the 2012 baseline emissions. Appendix V contains the 2011 audited emissions, and Appendix W contains the 2012 baseline emissions for power plants.

Appendix U – Staff's Proposal and CEQA Alternatives

Staff has considered many options to determine the most appropriate RTC shave distribution to effect emission reductions that will protect the environment, satisfy the CAA requirements, and satisfy AQMP commitments, while concurrently providing growth and safeguards to the operation of the RECLAIM program. The RTC reductions with the application of BARCT total 15.05 tons per day. However, an adjustment is proposed to the total RTC reduction to account for issues that have been raised by stakeholders regarding the BARCT analysis. These issues primarily focused on the potential uncertainties of the control costs for refinery boilers and heaters and the reliability and consistency in maintaining controlled NOx concentrations for the coke calciner. With these adjustments, the RTC reduction that would be applied for the shave approaches will total 14 tons per day.

The shave proposals under consideration affect four major groups within the NOx RECLAIM universe:

- Major Refineries and Investors
- Non-Major Refineries and Other Non-Refinery Facilities
- Power Plants
- Others (Bottom 10 percent of RTC Holders)

It should be noted that the power plants are being treated as a separate group because they are subject to NSR requirements for their equipment, which is mostly at BACT. Staff is considering a set-aside account for these facilities in order for them to continue compliance after the shave, given their NSR obligations of holding RTCs at the equipment's potential to emit level at the beginning of each compliance year. Also, the bottom 10 percent of RTC holders would be exempted from an RTC reduction for some of the shave proposals.

Staff's Proposal Under Consideration

This approach would affect the top 90 percent of RTC holders, which are comprised of fifty-seven total facilities, eight of which are the major refinery facilities. Investors would be added to this list and would count as if it was a single RECLAIM facility. Additionally, all power plants would be included in this option. The reductions for this sub-universe of facilities would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. RTC holdings for major refineries and investors would be shaved by 67 percent. For non-major refineries and all other facilities among the top 90 percent of RTC holders, the RTC holdings would be shaved by 47 percent. The holdings for the power plants would also be shaved by 47 percent. See Tables U.1 and U.2.

Table U. 1 - List of 65 Affected Facilities and Investors

Class	ID	Name	CY 2011 Emissions (tons/day)	IYB RTC Holding as of 3/20/2015 (tons/yr)	IYB RTC Holding as of 3/20/2015 (tons/day)
Refinery	800030	CHEVRON PRODUCTS CO.	1.95		2.82
Refinery	800089	EXXONMOBIL OIL CORPORATION	2.19		2.47
Refinery	174655	TESORO REFINING & MARKETING CO, LLC	1.69		2.30
Refinery	800436	TESORO REFINING AND MARKETING CO, LLC	1.61		1.83
Refinery	171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1.57		1.60
Refinery	800026	ULTRAMAR INC	0.73		1.38
Power Plant	115394	AES ALAMITOS, LLC	0.11		0.75
Power Plant	115663	EL SEGUNDO POWER, LLC	0.03		0.68
Power Plant	800074	LA CITY, DWP HAYNES GENERATING STATION	0.28		0.52
Other	800128	SO CAL GAS CO	0.63		0.49
Power Plant	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	0.14		0.49
Other	46268	CALIFORNIA STEEL INDUSTRIES INC	0.64		0.44
Power Plant	115536	AES REDONDO BEACH, LLC	0.06		0.40
Power Plant	160437	SOUTHERN CALIFORNIA EDISON	0.28		0.40
Refinery	171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	0.92		0.38
Refinery	174591	TESORO REF & MKTG CO LLC,CALCINER	0.56		0.37
Power Plant	115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	0.01		0.36
Power Plant	152707	CPV SENTINEL LLC	0.00		0.33
Other	169754	OXY USA INC	0.00		0.32
Power Plant	115389	AES HUNTINGTON BEACH, LLC	0.14		0.25
Other	7427	OWENS-BROCKWAY GLASS CONTAINER INC	0.19		0.21
Other	18931	TAMCO	0.31		0.20
Power Plant	4477	SO CAL EDISON CO	0.19		0.19
Refinery	800183	PARAMOUNT PETR CORP	0.14		0.19
Other	43201	SNOW SUMMIT INC	0.02		0.19
Other	172005	NEW- INDY ONTARIO, LLC	0.45		0.18
Power Plant	146536	WALNUT CREEK ENERGY, LLC	0.00		0.16
Other	800189	DISNEYLAND RESORT	0.06		0.15
Other	156741	HARBOR COGENERATION CO, LLC	0.00		0.14
Refinery	151798	TESORO REFINING AND MARKETING CO, LLC	0.13		0.14
Power Plant	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	0.07		0.13
Other	11435	PQ CORPORATION	0.11		0.13
Other	4242	SAN DIEGO GAS & ELECTRIC	0.20		0.13
Power Plant	115314	LONG BEACH GENERATION, LLC	0.02		0.12
Other	17953	PACIFIC CLAY PRODUCTS INC	0.03		0.12
Power Plant	153992	CANYON POWER PLANT	0.03		0.12
Other	800127	SO CAL GAS CO	0.00		0.11
Power Plant	800193	LA CITY, DWP VALLEY GENERATING STATION	0.23		0.11
Other	119907	BERRY PETROLEUM COMPANY	0.18		0.11
Power Plant	25638	BURBANK CITY, BURBANK WATER & POWER	0.01		0.10
Other	124838	EXIDE TECHNOLOGIES	0.09		0.10
Other	51620	WHEELABRATOR NORWALK ENERGY CO INC	0.12		0.09
Other	5973	SO CAL GAS CO	0.12		0.08

Power Plant	800168	PASADENA CITY, DWP	0.06		0.08
Other	3968	TABC, INC	0.00		0.08
Other	8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	0.06		0.07
Power Plant	155474	BICENT (CALIFORNIA) MALBURG LLC	0.05		0.07
Other	800181	CALIFORNIA PORTLAND CEMENT CO	0.00		0.07
Other	166073	BETA OFFSHORE	0.54		0.07
Other	114801	SOLVAY USA, INC.	0.07		0.07
Other	800153	US GOVT, NAVY DEPT LB SHIPYARD	0.00		0.07
Other	8547	QUEMETCO INC	0.06		0.07
Other	1073	BORAL ROOFING LLC	0.02		0.07
Power Plant	800170	LA CITY, DWP HARBOR GENERATING STATION	0.03		0.06
Power Plant	172077	CITY OF COLTON	0.00		0.04
Power Plant	139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	0.01		0.04
Power Plant	129810	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	0.00		0.03
Power Plant	164204	CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT	0.00		0.03
Power Plant	56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	0.01		0.01
Power Plant	14502	VERNON CITY, LIGHT & POWER DEPT	0.00		0.01
Power Plant	129816	INLAND EMPIRE ENERGY CENTER, LLC	0.15		0
Power Plant	127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	0.02		0
Power Plant	132191	PURENERGY OPERATING SERVICES, LLC	0.00		0
Power Plant	132192	PURENERGY OPERATING SERVICES, LLC	0.00		0
Power Plant	167432	EDISON MISSION HUNTINGTON BEACH, LLC*	0.00		0
Investors					1.16
*(Decommissioned in 2012)			**TOTAL HOLDINGS**		**23.85**
				23.85 / 26.51 =	**90%**

COUNTS

Major Refineries	9
Power Plants	30
Other	26
Investors	1
TOTAL	66

Table U. 2 – RTC Reductions Calculation

Refinery Reductions Beyond 2005 BARCT		6.06
Non-Refinery Reductions Beyond 2005 BARCT		2.77
	Total	8.83

Refinery Contribution to Emission Reduction (6.06 / 8.83 x 100)	69%
Non-Refinery Contribution to Emission Reduction (2.77 / 8.83 x 100)	31%

Total RTC Allocation	26.51
Remaining 2023 Emissions After BARCT and Growth	11.46
Minus BARCT Adjustment	0.85
Minus futher adjustment	0.20
Total RTC Reduction (26.51 - 11.46 - 0.85 - 0.2)	**14.00**

Weighted Reduction for Refinery (14.00 x 69%)	9.61
Weighted Reduction for Non-Refinery (14.00 x 31%)	4.39

Major Refinery + Investor Holdings for Top 90%	14.44
Non-Major Facility Holdings + All Power Plant Holdings for Top 90%	9.41
RTC Holdings for Top 90% of of Holders, Including Investors (14.44 + 9.41)	23.85

Remaining Major Refinery + Investor RTC Holdings (14.44 - 9.61)	4.83
% Shave to this Sub-Universe (9.61 / 14.44) x 100	**67%**

Remaining Non-Refinery RTC Holdings (9.41 - 4.39)	5.02
% Shave to this Sub-Universe (4.39 / 9.41) x 100	**47%**

RTC Reductions = Current RTC Holdings (26.51 tpd) – Remaining Emissions in 2023 (11.46 tpd) = 15.05 tpd

Total RTC reductions = 15.05 tpd – (BARCT adjustment of 0.85 tpd) – (Further adjustment of 0.2 tpd) = 14 tpd

CEQA Alternatives

Six CEQA alternatives are listed in Table U.3.

CEQA Alternative 1: This approach would be an across the board RTC reduction and would affect all RECLAIM facilities and investors. The RTC holdings would be shaved by 53 percent overall.

CEQA Alternative 2: This approach, the most stringent, would also be an across the board RTC reduction affecting all RECLAIM facilities and investors, but would not include the 10 percent compliance margin or the BARCT adjustment for refinery equipment. The total RTC reduction would be 15.87 tons per day under this approach and the RTC holdings would be shaved by 60 percent overall.

CEQA Alternative 3: This approach has been proposed by industry representatives and is an across the board shave that would affect all RECLAIM facilities and investors. For this calculation, the base year emissions at the proposed BARCT level would be subtracted from the base year emissions at the previous BARCT level (Year 2000 or 2005). The result would be an RTC reduction of 33 percent to all RECLAIM facilities and investors.

CEQA Alternative 4: This is the "No Project" approach and no RTC reduction would be applied to any RECLAIM facility or investor.

CEQA Alternative 5: This approach would affect all RECLAIM facilities and investors. The RTC reductions would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. RTC holdings for major refineries and investors would be shaved by 67 percent. For non-major refineries and all other facilities, the RTC holdings would be shaved by 36 percent.

CEQA Alternative 6: This approach would affect the top 90 percent of RTC holders, which are comprised of fifty-seven total facilities, eight of which are the major refinery facilities. Investors would be added to this list and would count as if it was a single RECLAIM facility. The reductions for this sub-universe of facilities would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. RTC holdings for major refineries and investors would be shaved by 67 percent. For non-major refineries and all other facilities among the top 90 percent of RTC holders, the RTC holdings would be shaved by 47 percent.

Table U. 3 - NOx RECLAIM Shave Options and CEQA Alternatives Under Consideration

		Major Refineries/Investors	Non-Major Facilities	Power Plants	Bottom 10% of Holders
	Staff Proposal Under Consideration				
Staff Proposal	**Shave applied to 90% of RTC Holders (Weighted by BARCT Reduction Contribution)** *69 total facilities, plus investors as 1 company, and includes 48 non-major refinery facilities **ALSO INCLUDES ALL POWER PLANTS***	**67%** **(9 Facilities)**	**47%** **(26 Facilities)**	**47%** **(30 Facilities)**	**0%** **(211 Facilities)**
	CEQA Alternatives Under Consideration				
CEQA Alternative #1	**Across the Board** *Affects all facilities and investors*	**53%**	**53%**	**53%**	**53%**
CEQA Alternative #2	**Most Stringent Approach** *Across the Board without 10% Compliance Margin*	**60%**	**60%**	**60%**	**60%**
CEQA Alternative #3	**Industry Approach** *Across the Board: Difference between previous BARCT and new BARCT*	**33%**	**33%**	**33%**	**33%**
CEQA Alternative #4	**No Project**	**0%**	**0%**	**0%**	**0%**
CEQA Alternative #5	**Weighted by BARCT Reduction Contribution** *Affects all facilities and investors*	**67%**	**36%**	**36%**	**36%**
CEQA Alternative #6	**Shave applied to 90% of RTC Holders (Weighted by BARCT Reduction Contribution)** *57 total facilities, plus investors as 1 company, and includes 48 non-major refinery facilities.*	**67%**	**47%**	**47%**	**0%**

Tradable/Usable and Non-Tradable/Non-Usable Factors in Rules 2002(f)(1)(B) and (C)

The Tradable/Usable NOx Adjustment Factor is derived by dividing the amount of RTCs remaining after the shave for each compliance year by the total holdings prior to the beginning of the shave. For those facilities subject to subparagraph (f)(1)(B) [listed in Rule 2002 Table 7], the total holdings prior to the beginning of the shave is 14.44 tons per day. Similarly, for those facilities subject to subparagraph (f)(1)(C) [listed in Rule 2002 Table 8], the total holdings prior to the beginning of the shave is 9.41 tons per day. Both of these values are presented in Table U.2 of this report.

The proposed RTC reduction for each compliance year is presented in Chapter 5 of this report:

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

The proportion of RTC reductions based on initial holdings and remaining RTCs for the Table 7 and Table 8 facilities is as follows:

Compliance Year	Table 7 Facilities		Table 8 Facilities	
	Reductions (tpd)	**A_i Remaining (tpd)**	**Reductions (tpd)**	**B_i Remaining (tpd)**
2016	2.75	11.69	1.25	8.16
2017	0	11.69	0	8.16
2018	1.37	10.32	0.63	7.53
2019	1.37	8.95	0.63	6.9
2020	1.37	7.58	0.63	6.27
2021	1.37	6.21	0.63	5.64
2022	1.37	4.84	0.63	5.01

The Tradable/Usable NOx Adjustment Factor is calculated as follows:

Table 7 Facilities = $A_i/14.44$

Table 8 Facilities = $B_i/9.41$

The Non-tradable/Non-usable NOx Adjustment Factor is derived by dividing the cumulative amount of RTC reductions starting in the 2018 shave by the total holdings prior to the beginning of the shave. For the Table 7 and 8 facilities the cumulative amount of RTC reductions would be as follows:

Compliance Year	Table 7 Facilities RTC Reductions		Table 8 Facilities RTC Reductions	
	Annual (tpd)	**Cumulative (C_i) (tpd)**	**Annual (tpd)**	**Cumulative (D_i) (tpd)**
2018	1.37	1.37	0.63	0.63
2019	1.37	2.74	0.63	1.26
2020	1.37	4.11	0.63	1.89
2021	1.37	5.48	0.63	2.52
2022	1.37	6.85	0.63	3.15

The Non-tradable/Non-usable NOx Adjustment Factor is calculated as follows:

Table 7 Facilities = $C_i/14.44$

Table 8 Facilities = $D_i/9.41$

Appendix V – 2011 Audited Emissions of 20 tons per day

The 2011 audited NOx emissions for the 281 facilities in RECLAIM were shown in Table V-1.

Table V. 1 - 2011 Audited Emissions

			2011 Emissions (lbs)	2011 Emissions (tpd)
1	131003	BP WEST COAST PROD.LLC BP CARSON REF.	1,231,852	1.69
2	131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	407,394	0.56
3	151798	TESORO REFINING AND MARKETING CO, LLC	93,488	0.13
4	171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1,143,902	1.57
5	171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	673,652	0.92
6	800026	ULTRAMAR INC (NSR USE ONLY)	534,363	0.73
7	800030	CHEVRON PRODUCTS CO.	1,425,393	1.95
8	800089	EXXONMOBIL OIL CORPORATION	1,602,233	2.19
9	800183	PARAMOUNT PETR CORP (EIS USE)	104,249	0.14
10	800436	TESORO REFINING AND MARKETING CO, LLC	1,171,965	1.61
		Total Refineries		**11.49**
1	4242	SAN DIEGO GAS & ELECTRIC	142,751	0.20
2	4477	SO CAL EDISON CO	137,290	0.19
3	5973	SO CAL GAS CO	88,258	0.12
4	7427	OWENS-BROCKWAY GLASS CONTAINER INC	135,486	0.19
5	11435	PQ CORPORATION	81,270	0.11
6	15504	SCHLOSSER FORGE COMPANY	52,331	0.07
7	18931	TAMCO	226,012	0.31
8	22911	CARLTON FORGE WORKS	48,839	0.07
9	46268	CALIFORNIA STEEL INDUSTRIES INC	464,990	0.64
10	51620	WHEELABRATOR NORWALK ENERGY CO INC	89,025	0.12
11	114801	RHODIA INC.	48,878	0.07
12	115389	AES HUNTINGTON BEACH, LLC	98,993	0.14
13	115394	AES ALAMITOS, LLC	80,929	0.11
14	119907	BERRY PETROLEUM COMPANY	131,857	0.18
15	124838	EXIDE TECHNOLOGIES	62,824	0.09
16	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49,983	0.07
17	129497	THUMS LONG BEACH CO	66,364	0.09
18	129816	INLAND EMPIRE ENERGY CENTER, LLC	105,857	0.15
19	160437	SOUTHERN CALIFORNIA EDISON	204,132	0.28
20	166073	BETA OFFSHORE	391,977	0.54
21	171960	TIN, INC. DBA INTERNATIONAL PAPER	327,637	0.45
22	800074	LA CITY, DWP HAYNES GENERATING STATION	205,022	0.28
23	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	103,988	0.14
24	800128	SO CAL GAS CO (EIS USE)	461,243	0.63
25	800193	LA CITY, DWP VALLEY GENERATING STATION	166,413	0.23
26	800330	THUMS LONG BEACH	49,657	0.07
27	800335	LA CITY, DEPT OF AIRPORTS	73,245	0.10
		Total non-refineries		**5.61**
		Total for top 37 emitting facilities		**17.10**

1	800189	DISNEYLAND RESORT	47,216	0.06
2	8547	QUEMETCO INC	46,831	0.06
3	126498	STEELSCAPE, INC	46,420	0.06
4	101656	AIR PRODUCTS AND CHEMICALS, INC.	44,275	0.06
5	8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	42,884	0.06
6	800168	PASADENA CITY, DWP (EIS USE)	41,370	0.06
7	115536	AES REDONDO BEACH, LLC	40,890	0.06
8	9755	UNITED AIRLINES INC	40,626	0.06
9	94872	METAL CONTAINER CORP	39,730	0.05
10	800080	LUNDAY-THAGARD COMPANY	39,275	0.05
11	155474	BICENT (CALIFORNIA) MALBURG LLC	38,772	0.05
12	105903	PRIME WHEEL	37,852	0.05
13	43436	TST, INC.	35,778	0.05
14	148236	AIR LIQUIDE LARGE INDUSTRIES U.S., LP	33,031	0.05
15	3417	AIR PROD & CHEM INC	32,660	0.04
16	14495	VISTA METALS CORPORATION	30,433	0.04
17	139010	RIPON COGENERATION LLC	30,419	0.04
18	16639	SHULTZ STEEL CO	30,415	0.04
19	47781	OLS ENERGY-CHINO	29,938	0.04
20	550	LA CO., INTERNAL SERVICE DEPT	29,202	0.04
21	118406	CARSON COGENERATION COMPANY	28,760	0.04
22	155877	MILLERCOORS, LLC	28,439	0.04
23	800409	NORTHROP GRUMMAN SYSTEMS CORPORATION	27,489	0.04
24	800037	DEMENNO/KERDOON	26,951	0.04
25	16338	KAISER ALUMINUM FABRICATED PRODUCTS, LLC	25,667	0.04
1	136	PRESS FORGE CO	25,407	0.03
2	3704	ALL AMERICAN ASPHALT, UNIT NO.01	24,416	0.03
3	16642	ANHEUSER-BUSCH LLC., (LA BREWERY)	23,205	0.03
4	35302	OWENS CORNING ROOFING AND ASPHALT, LLC	23,022	0.03
5	800170	LA CITY, DWP HARBOR GENERATING STATION	22,609	0.03
6	115663	EL SEGUNDO POWER, LLC	21,639	0.03
7	11887	NASA JET PROPULSION LAB	21,140	0.03
8	153992	CANYON POWER PLANT	21,077	0.03
9	17953	PACIFIC CLAY PRODUCTS INC	20,635	0.03
10	346	FRITO-LAY, INC.	20,492	0.03
11	68042	CORONA ENERGY PARTNERS, LTD	19,286	0.03
12	18294	NORTHROP GRUMMAN CORP, AIRCRAFT DIV	18,299	0.03
13	3585	R. R. DONNELLEY & SONS CO, LA MFG DIV	16,710	0.02
14	800016	BAKER COMMODITIES INC	16,616	0.02
15	12428	NEW NGC, INC.	16,418	0.02
16	7411	DAVIS WIRE CORP	16,090	0.02
17	83102	LIGHT METALS INC	15,731	0.02
18	54402	SIERRA ALUMINUM COMPANY	15,677	0.02
19	117785	BALL METAL BEVERAGE CONTAINER CORP.	15,323	0.02
20	117290	B BRAUN MEDICAL, INC	15,167	0.02
21	151532	LINN OPERATING, INC	15,146	0.02
22	800408	NORTHROP GRUMMAN SYSTEMS	14,835	0.02
23	52517	REXAM BEVERAGE CAN COMPANY	14,827	0.02

24	115172	RAYTHEON COMPANY	14,365	0.02
25	21887	KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	14,070	0.02
26	800088	3M COMPANY	13,446	0.02
27	800113	ROHR, INC.	12,593	0.02
28	115563	NCI GROUP INC., DBA, METAL COATERS OF CA	12,471	0.02
29	115314	LONG BEACH PEAKERS LLC	12,363	0.02
30	1073	BORAL ROOFING LLC	12,063	0.02
31	23752	AEROCRAFT HEAT TREATING CO INC	11,919	0.02
32	45746	PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	11,885	0.02
33	3029	MATCHMASTER DYEING & FINISHING INC	11,691	0.02
34	127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	11,529	0.02
35	43201	SNOW SUMMIT INC	11,028	0.02
36	800066	HITCO CARBON COMPOSITES INC	10,783	0.01
37	115315	GEN ON WEST, LP	10,625	0.01
38	61962	LA CITY, HARBOR DEPT	10,436	0.01
39	9053	VEOLIA ENERGY LOS ANGELES, INC	10,120	0.01
40	53729	TREND OFFSET PRINTING SERVICES, INC	10,005	0.01
41	97081	THE TERMO COMPANY	9,943	0.01
42	85943	SIERRA ALUMINUM COMPANY	9,856	0.01
43	22364	ITT CORPORATION	9,853	0.01
44	45471	O N I S, DBA, CARMEUSE INDUSTRIAL SANDS	9,784	0.01
45	800393	VALERO WILMINGTON ASPHALT PLANT	9,556	0.01
46	16978	CLOUGHERTY PACKING LLC/HORMEL FOODS CORP	9,424	0.01
47	61722	RICOH ELECTRONICS INC	9,200	0.01
48	22607	CALIFORNIA DAIRIES, INC	9,148	0.01
49	115241	BOEING SATELLITE SYSTEMS INC	9,142	0.01
50	101977	SIGNAL HILL PETROLEUM INC	8,791	0.01
51	131732	NEWPORT FAB, LLC	8,769	0.01
52	21598	ANGELICA TEXTILE SERVICES	8,675	0.01
53	139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	8,579	0.01
54	123774	HERAEUS PRECIOUS METALS NO. AMERICA, LLC	8,552	0.01
55	16737	ATKINSON BRICK CO	8,448	0.01
56	145836	AMERICAN APPAREL DYEING & FINISHING, INC	8,416	0.01
57	130211	PAPER-PAK INDUSTRIES	8,385	0.01
58	132068	BIMBO BAKERIES USA INC	8,379	0.01
59	800372	EQUILON ENTER. LLC, SHELL OIL PROD. US	8,284	0.01
60	157359	HENKEL ELECTRONIC MATERIALS, LLC	7,990	0.01
61	800196	AMERICAN AIRLINES INC (EIS USE)	7,985	0.01
62	115130	VERTIS, INC	7,890	0.01
63	37603	SGL TECHNIC INC, POLYCARBON DIVISION	7,638	0.01
64	19390	SULLY-MILLER CONTRACTING CO.	7,459	0.01
65	38872	MARS PETCARE U.S., INC.	7,248	0.01
66	131850	SHAW DIVERSIFIED SERVICES INC	7,207	0.01
67	3721	DART CONTAINER CORP OF CALIFORNIA	7,078	0.01
68	107656	CALMAT CO	7,014	0.01
69	56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	7,004	0.01
70	2825	MCP FOODS INC	6,991	0.01
71	800150	US GOVT, AF DEPT, MARCH AIR RESERVE BASE	6,892	0.01
72	11119	THE GAS CO./ SEMPRA ENERGY	6,820	0.01
73	152501	PRECISION SPECIALTY METALS, INC.	6,773	0.01
74	2912	HOLLIDAY ROCK CO INC	6,761	0.01
75	59618	PACIFIC CONTINENTAL TEXTILES, INC.	6,659	0.01
76	19167	R J NOBLE COMPANY	6,626	0.01
77	40034	BENTLEY PRINCE STREET INC	6,205	0.01

69	56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	7,004	0.01
70	2825	MCP FOODS INC	6,991	0.01
71	800150	US GOVT, AF DEPT, MARCH AIR RESERVE BASE	6,892	0.01
72	11119	THE GAS CO./ SEMPRA ENERGY	6,820	0.01
73	152501	PRECISION SPECIALTY METALS, INC.	6,773	0.01
74	2912	HOLLIDAY ROCK CO INC	6,761	0.01
75	59618	PACIFIC CONTINENTAL TEXTILES, INC.	6,659	0.01
76	19167	R J NOBLE COMPANY	6,626	0.01
77	40034	BENTLEY PRINCE STREET INC	6,205	0.01
78	25638	BURBANK CITY, BURBANK WATER & POWER	6,137	0.01
79	800038	THE BOEING COMPANY - C17 PROGRAM	6,092	0.01
80	18455	ROYALTY CARPET MILLS INC	5,997	0.01
81	138568	CALIFORNIA DROP FORGE, INC	5,977	0.01
82	114997	RAYTHEON COMPANY	5,819	0.01
83	153199	THE KROGER CO/RALPHS GROCERY CO	5,639	0.01
84	161300	SAPA EXTRUDER, INC	5,600	0.01
85	96587	TEXOLLINI INC	5,573	0.01
86	165192	TRIUMPH AEROSTRUCTURES, LLC	5,464	0.01
87	115277	LAFAYETTE TEXTILE IND LLC	5,409	0.01
88	74424	ANGELICA TEXTILE SERVICES	5,347	0.01
89	137471	GRIFOLS BIOLOGICALS INC	5,246	0.01
90	153033	GEORGIA-PACIFIC CORRUGATED LLC	5,223	0.01
91	12155	ARMSTRONG WORLD INDUSTRIES INC	5,032	0.01
92	73022	US AIRWAYS INC	4,988	0.01
93	107654	CALMAT CO	4,897	0.01
94	156722	AMERICAN APPAREL KNIT AND DYE	4,841	0.01
95	11034	VEOLIA ENERGY LOS ANGELES, INC	4,831	0.01
96	800003	HONEYWELL INTERNATIONAL INC	4,826	0.01
97	141295	LEKOS DYE AND FINISHING, INC	4,686	0.01
98	124619	ARDAGH METAL PACKAGING USA INC.	4,543	0.01
99	155221	SAVE THE QUEEN LLC (DBA QUEEN MARY)	4,224	0.01
100	1744	KIRKHILL - TA COMPANY	4,003	0.01
101	11716	FONTANA PAPER MILLS INC	3,971	0.01
102	800417	PLAINS WEST COAST TERMINALS LLC	3,963	0.01
103	133987	PLAINS EXPLORATION & PRODUCTION CO, LP	3,883	0.01
104	143741	DCOR LLC	3,850	0.01
105	800149	US BORAX INC	3,825	0.01
106	63180	DARLING INTERNATIONAL INC	3,659	0.01
107	148925	CHERRY AEROSPACE	3,634	0.00
108	20604	RALPHS GROCERY CO	3,629	0.00
109	800094	EXXONMOBIL OIL CORPORATION	3,545	0.00
110	20203	RECYCLE TO CONSERVE INC.	3,542	0.00

110	20203	RECYCLE TO CONSERVE INC.	3,542	0.00
111	800067	BOEING SATELLITE SYSTEMS INC	3,409	0.00
112	117140	AOC, LLC	3,247	0.00
113	167066	ARLON GRAPHICS L.L.C.	3,239	0.00
114	5998	ALL AMERICAN ASPHALT	3,235	0.00
115	114264	ALL AMERICAN ASPHALT	3,233	0.00
116	15544	REICHHOLD INC	3,189	0.00
117	800338	SPECIALTY PAPER MILLS INC	3,097	0.00
118	800431	PRATT & WHITNEY ROCKETDYNE, INC.	3,028	0.00
119	17956	WESTERN METAL DECORATING CO	3,023	0.00
120	2946	PACIFIC FORGE INC	2,938	0.00
121	113160	HILTON COSTA MESA	2,936	0.00
122	42630	PRAXAIR INC	2,737	0.00
123	157363	INTERNATIONAL PAPER CO	2,661	0.00
124	107653	CALMAT CO	2,577	0.00
125	17623	LOS ANGELES ATHLETIC CLUB	2,511	0.00
126	50098	D&D DISPOSAL INC,WEST COAST RENDERING CO	2,501	0.00
127	98159	PACIFIC COAST ENERGY COMPANY LP	2,384	0.00
128	125015	LOS ANGELES TIMES COMMUNICATIONS LLC	2,339	0.00
129	95212	FABRICA	2,296	0.00
130	14871	SONOCO PRODUCTS CO	2,291	0.00
131	3968	TABC, INC	2,283	0.00
132	156741	HARBOR COGENERATION CO, LLC	2,277	0.00
133	124808	INEOS POLYPROPYLENE LLC	2,247	0.00
134	112853	NP COGEN INC	2,206	0.00
135	107655	CALMAT CO	2,182	0.00
136	2418	FRUIT GROWERS SUPPLY CO	2,083	0.00
137	94930	CARGILL INC	2,032	0.00
138	133813	EI COLTON, LLC	1,965	0.00
139	14049	MARUCHAN INC	1,949	0.00
140	168088	PCCR USA	1,903	0.00
141	800325	TIDELANDS OIL PRODUCTION CO	1,872	0.00
142	25058	EXXONMOBIL OIL CORP	1,787	0.00
143	800127	SO CAL GAS CO (EIS USE)	1,778	0.00
144	143740	DCOR LLC	1,741	0.00
145	105277	SULLY MILLER CONTRACTING CO	1,740	0.00
146	800181	CALIFORNIA PORTLAND CEMENT CO (NSR USE)	1,727	0.00
147	10094	ATLAS CARPET MILLS INC	1,726	0.00
148	117227	SHCI SM BCH HOTEL LLC, LOEWS SM BCH HOTE	1,724	0.00
149	158950	WINDSOR QUALITY FOOD CO. LTD.	1,701	0.00
150	800420	PLAINS WEST COAST TERMINALS LLC	1,690	0.00
151	42775	WEST NEWPORT OIL CO	1,661	0.00
152	143738	DCOR LLC	1,570	0.00
153	144455	LIFOAM INDUSTRIES, LLC	1,497	0.00
154	164204	CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT	1,476	0.00

155	14736	THE BOEING COMPANY	1,458	0.00
156	169754	OXY USA INC	1,438	0.00
157	800416	PLAINS WEST COAST TERMINALS LLC	1,426	0.00
158	800110	THE BOEING COMPANY	1,369	0.00
159	800371	RAYTHEON SYSTEMS COMPANY - FULLERTON OPS	1,302	0.00
160	111415	VAN CAN COMPANY	1,268	0.00
161	115041	RAYTHEON COMPANY	1,188	0.00
162	800210	CONEXANT SYSTEMS INC	1,166	0.00
163	132071	DEAN FOODS CO. OF CALIFORNIA	1,164	0.00
164	151594	OXY USA, INC	1,132	0.00
165	5814	GAINEY CERAMICS INC	1,126	0.00
166	7416	PRAXAIR INC	1,108	0.00
167	124723	GREKA OIL & GAS, INC	1,025	0.00
168	17344	EXXONMOBIL OIL CORP	977	0.00
169	148340	THE BOEING CO. COMMERCIAL AVIATION SRVCS	950	0.00
170	14926	SEMPRA ENERGY (THE GAS CO)	948	0.00
171	89248	OLD COUNTRY MILLWORK INC	930	0.00
172	129810	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	866	0.00
173	800205	BANK OF AMERICA NT & SA, BREA CENTER	859	0.00
174	132191	PURENERGY OPERATING SERVICES, LLC	826	0.00
175	68118	TIDELANDS OIL PRODUCTION COMPANY ETAL	823	0.00
176	12372	MISSION CLAY PRODUCTS	787	0.00
177	16660	THE BOEING COMPANY	761	0.00
178	142267	FS PRECISION TECH LLC	739	0.00
179	47771	DELEO CLAY TILE CO INC	657	0.00
180	151899	VINTAGE PRODUCTION CALIFORNIA LLC	645	0.00
181	133996	PLAINS EXPLORATION & PRODUCTION COMPANY	611	0.00
182	14944	CENTRAL WIRE, INC.	564	0.00
183	800264	EDGINGTON OIL COMPANY	481	0.00
184	800182	RIVERSIDE CEMENT CO (EIS USE)	456	0.00
185	800344	CALIFORNIA AIR NATIONAL GUARD, MARCH AFB	425	0.00
186	40483	NELCO PROD. INC	282	0.00
187	160888	HINES REIT EL SEGUNDO, LP	271	0.00
188	125579	DIRECTV	268	0.00
189	9217	VEOLIA ENERGY LOS ANGELES, INC	220	0.00
190	14502	VERNON CITY, LIGHT & POWER DEPT	172	0.00
191	137508	TONOGA INC, TACONIC DBA	93	0.00
192	143739	DCOR LLC	79	0.00
193	2083	SUPERIOR INDUSTRIES INTERNATIONAL INC	75	0.00
194	142536	DRS SENSORS & TARGETING SYSTEMS, INC	72	0.00
195	149491	BOEING REALTY CORP	49	0.00
196	132192	PURENERGY OPERATING SERVICES, LLC	29	0.00
197	800373	CENCO REFINING COMPANY	25	0.00
198	12185	US GYPSUM CO	5	0.00

199	141555	CASTAIC CLAY PRODUCTS, LLC	4	0.00
200	151394	LINN WESTERN OPERATING INC	4	0.00
201	152054	LINN WESTERN OPERATING INC	3	0.00
202	58622	LOS ANGELES COLD STORAGE CO	1	0.00
203	151415	LINN WESTERN OPERATING, INC	1	0.00
204	1634	STEELCASE INC, WESTERN DIV	0	0.00
205	15164	HIGGINS BRICK CO	0	0.00
206	20543	REDCO II	0	0.00
207	23196	SUNKIST GROWERS, INC	0	0.00
208	38440	COOPER & BRAIN - BREA	0	0.00
209	42676	CES PLACERITA INC	0	0.00
210	119104	CALMAT CO	0	0.00
211	137520	PLAINS WEST COAST TERMINALS LLC	0	0.00
212	146536	WALNUT CREEK ENERGY, LLC	0	0.00
213	148896	VINTAGE PRODUCTION CALIFORNIA LLC	0	0.00
214	148897	VINTAGE PRODUCTION CALIFORNIA LLC	0	0.00
215	151601	OXY USA, INC.	0	0.00
216	152707	CPV SENTINEL LLC	0	0.00
217	152857	GEORGIA-PACIFIC GYPSUM LLC	0	0.00
218	800343	BOEING SATELLITE SYSTEMS, INC	0	0.00
219	800419	PLAINS WEST COAST TERMINALS LLC	0	0.00
	TOTAL (281 Facilities by end of June 2011)			**20.006**
	Note: August 29, 2013 data from RECLAIM Admin team			

Appendix W – 2012 Emissions for Power Generating Sector

The base year for the BARCT analysis is compliance year 2011. However, the 2011 base year would not be appropriate for this source category due to the uniqueness of its operations. There have been several changes within recent years that have warranted the use of more recent base year data.

The San Onofre Nuclear Generating Station (SONGS) has not been in operation since early 2012 and is now undergoing decommissioning. The power deficit was to be made up by other natural gas fired units in the region. Other existing units are subject to the once-through-cooling (OTC) regulation and will have to be repowered. These repowered units are predicted to be more efficient units that consume less natural gas to produce the same amount of power as their predecessors. Other trends in the industry have begun to affect power availability such as the increased use of renewable power, like wind, water, and solar. The state of California must meet a 33% Renewable Portfolio Standard by 2020, and the inherent volatility of these renewable energy sources means that gas demand must be met almost in real time.

Based on the 2014 California Gas Report, gas demand in the future is set to decrease slightly due to the utilization of more efficient power plants, greenhouse gas (GHG) reductions, and the increased use of renewable power. The projected emissions in 2023 using compliance year 2011 as the base year used growth factors from SCAG (Southern California Association of Governments).

Table W. 1 - Compliance Year 2011 Power Generating Sector Emissions

Compliance Year 2011 Emissions (tpd)	2011 Emissions at BARCT/BACT (tpd)	Growth Factor	2023 Emissions with Growth (tpd)
1.45	2.57	1.146	2.95

The figures above included those power plants among the top 37 NOx emitters in compliance year 2011. An additional 0.34 tons per day came from power plants outside the top 37 and was included as part of the “Other Sources” category with a different growth factor.

More recent base year data was obtained using calendar year AER (Annual Emissions Report) fuel usage data for 2012. The calendar year 2012 emissions include those for the major sources only belonging to power plant source category (includes boilers, gas turbines, and ICEs). The emissions from process units and any Rule 219 equipment are almost negligible (the emissions from process units in 2011 were 0.006 tpd).

Table W. 2 - 2012 Power Generating Sector Emissions Based on Annual Emission Reports (AER) Fuel Usage

Calendar Year 2012 Emissions (tpd)	2012 Emissions at BARCT/BACT (tpd)	Growth Factor	2023 Emissions with Growth (tpd)
2.50	2.35	0.8683	2.04

The growth factor was extrapolated from the tables in the 2104 California Gas Report and it shows a slight decrease in demand for natural gas. There were nine power plants among the top 37 emitters in compliance year 2011. For this updated analysis, all power plants in RECLAIM were included (30 in total) and their emissions at the BARCT or BACT level were calculated. Power plants are unique in that most of the units are already meeting BARCT or BACT requirements.

Another unique aspect of the power generating sector is that many of the newer units are subject to new source review (NSR) holding requirements. Per Rule 2005, if a facility is new (received all its District permits on or after October 15, 1993), it must hold sufficient RTCs in advance of every year at the equipment's potential to emit level. Virtually all power generating units typically operate at a level far below its potential to emit, but the facility must still hold the RTCs to comply with the NSR demonstration. Stakeholders have brought to SCAQMD staff's attention their concern about the shave and whether a power generating facility can still comply with its emission allocation and NSR demonstration concurrently, especially when there is no cost effective method to retrofit their equipment to generate credits.

SCAQMD staff has proposed a safety valve for addressing the concerns of the power generating sector. An adjustment account has been proposed that would consist of RTCs solely to meet the programmatic NSR holding demonstration. Under this approach, individual facility holding requirements would no longer be necessary. A power generating facility would only be allowed access to discrete year only credits at the current program review threshold level of $15,000 per ton. Concerns have also been raised in the event that a power emergency is experienced and there is an added demand for power production. SCAQMD staff has also proposed to allow access to the adjustment account if the state of California declares a state of emergency. The size of the adjustment account is still being discussed, but the total amount of the shave would be applied first, followed by the adjustment account RTCs. Those equivalent emission reductions for the adjustment account would not be submitted to the state implementation plan (SIP).

Appendix X – Proposed Changes in Rules 2002, 2005, 2011 and 2012

Rule 2002

The staff proposal calls for a programmatic reduction of 14 tons per day in two phases. Four tons per day would be reduced in 2016 and the remainder would be reduced in equal increments from 2018 to 2022. There would be no reductions proposed for the year 2017. These reductions are reflected in subparagraphs (f)(1)(B) and (f)(1)(C). Subparagraph (f)(1)(B) includes all of Major Refineries and Investors. The Major Refineries are listed in Table 7 of Rule 2002. Subparagraph (f)(1)(C) includes all of facilities subject to the reduction in NOx RTCs. These facilities are listed in Table 8 of Rule 2002.

Thus the remaining NOx RTCs after a shave for any compliance year would be the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(B) multiplied by the RTC holdings (as of March 20, 2015) of all the Major Refineries listed in Table 7 plus the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(C) multiplied by the RTC holdings (as of March 20, 2015) of all the facilities listed in Table 8.

Since the RTC reductions specified in subparagraph (f)(1)(A) have been realized the conversion of non-tradable/non-usable NOx RTCs to tradable/usable NOx RTCs is no longer applicable to the RTC reductions specified in this subparagraph. The tradable/usable NOx RTCs specified in subparagraph (f)(1)(A) would remain intact and used for calculating RTC reductions for facilities entering the RECLAIM program. However the same approach in converting adjustment factors previously specified in subparagraph (f)(1)(A) would now be applied to the RTC reductions specified in subparagraphs (f)(1)(B) and (f)(1)(C).

A new Power Producing facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. Staff is proposing to create an Adjustment Account that would be used for the purpose of complying with the requirements specified in Rule 2005. The Executive Officer will determine and distribute the RTCs from this Adjustment Account according to the needs of each Power Producing Facility as specified in their Facility Permit. These proposed requirements are specified in Rule 2002 paragraph (f)(4).

Staff is also proposing in paragraph (f)(5) that during a State of Emergency as declared by the Governor, the Executive Officer will allow Power Producing Facilities access to the Adjustment

Account RTCs for the purpose of compliance with the annual emissions. The available RTCs would be limited to those that are in excess of those specified for use in paragraph (f)(4). The amount and distribution of the RTCs will be determined by the Executive Officer based on the impact that the State of Emergency has on the RECLAIM program.

It is estimated that the needed RTCs in the Adjustment Account for the new Power Producing facilities would be 1 to 1 ½ tons per day. These Adjustment Account RTCs would be extracted from the proposed programmatic 14 tons per day reductions.

Facilities seeking an exemption from the proposed RECLAIM shave as specified in subdivision (i) would be required to meet the new BARCT emission factors as shown in Table 6 of Rule 2002. Consequently, the shave exemption would be based on the more stringent emission factor specified in Tables 3 (factors generated in the January 7, 2005 amendment to Rule 2002) and 6.

Rule 2005

Rule 2005 sets forth requirements for new or modified equipment or processes at RECLAIM facilities. The purpose of the rule is to ensure that the RECLAIM program is equivalent to the federal and state NSR program requirements. Rule 2005 provides three separate requirements to meet the NSR programmatic equivalency:

1) Sources causing emission increases must be equipped with Best Available Control Technology (BACT),

2) Modeling must be used to demonstrate that operation of the source will not result in a significant increase in the air quality concentration of nitrogen dioxide (NO_2) if the facility total emissions exceed its 1994 starting allocations plus non-tradable credits, and

3) The facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter.

These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. The evaluation of emission increases under this paragraph is defined on a device-by-device basis at the maximum potential to emit. Any time a new NOx- (or SOx)-emitting RECLAIM device is installed, it triggers the credit holding requirements because it does not have any prior emissions, even in cases where the new device is replacing an older, dirtier device.

Among these requirements, the credit holding requirement ensures that the facility has adequate credits to offset emission increases year-by-year. It does not directly require emission decreases. On the other hand, all RECLAIM facilities are required to reconcile their Allocations to their emissions (i.e. hold enough RTCs to cover their emissions) by the end of each quarter and each compliance year pursuant to Rule 2004 – Requirements. Therefore, under RECLAIM, all facilities are required to have credits to offset all RECLAIM emissions regardless if they are subject to the requirements of Rule 2005.

The amendments made in June 3, 2011 required an existing RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but will not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocations plus non-tradable credits.

The offset requirements for new RECLAIM facilities remained unchanged. Thus a new facility will have to continue to hold adequate RTCs equal to the amount of emission increases at the beginning of each compliance year. Any excess RTCs cannot be sold until the end of the compliance year, or the applicable quarters if the facility has permit conditions to cap its emissions during each quarter, thus allowing sale of unused RTCs at the end of the quarter.

To remedy this holding requirement for new Power Producing facilities that cannot change their allowable NOx emissions in their Facility Permit staff is proposing an Adjustment Account. Proposed changes in Rule 2005 would assure that the Adjustment Account RTCs would only be used the for the purpose of complying with the NSR requirements.

Other Administrative Amendments

Besides the changes described in Rule 2002 and 2005 above, staff also proposes administrative amendments to Regulation XX to clarify the rule language and to ensure effective and consistent implementation of the RECLAIM program.

Rule 2002(b) - 5-Year Limitation on Amending Annual Emission Reports

Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) specifies the procedures for quantifying RECLAIM allocations for facilities in the original (1994) RECLAIM universe, facilities electing to enter the program, and facilities included into the program because they experienced actual NOx or SOx emissions of four tons or more in a year. Allocations are quantified by multiplying throughput levels (*e.g.*, quantity of fuel consumed or of material processed) documented in peak year Annual Emission Reports (AERs), by emission factors specified in Rule 2002. However, if the emission factors used in preparing the peak year AER reports are lower than those in Rule 2002, then the lower factors are to be used for quantifying allocations.

Some facilities entering the RECLAIM program have sought to amend their past AERs, which dated as far back as 1989, in ways that increase the initial SOx and/or NOx allocations quantified for them pursuant to Rule 2002. The longer the time elapsed between the reporting period and submittal of the correction the more problematic the process of validating the proposed corrections and their supporting documentation becomes. In fact, such validation has been infeasible in some cases. Therefore, staff is proposing to add paragraph (b)(5) to Rule 2002 specifying that the Executive Officer will not consider any AER data submitted beyond the original due date for the reporting period when calculating a facility's allocation. This language would provide clarity to RECLAIM facilities and potential RECLAIM facilities regarding what AR submittals and/or revisions may be considered in determining their allocations, as well as relieve the costs, both financial and in terms of staff resources, associated with review and validation of AER submittals made long after the reporting periods for which they are submitted.

Rules 2011 and 2012 - Delayed RATA Tests due to Extenuating Circumstances

Rules 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions set forth monitoring, reporting, and recordkeeping requirements for sources of SOx and NOx at RECLAIM facilities. The accompanying Appendices A to these rules, Rule 2011 – Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions and Rule 2012 – Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions, outline in greater detail the technical specifications required for monitoring, reporting, and recordkeeping for RECLAIM sources. Moreover, Attachment C, Subdivision B, Paragraph 2 of Appendix A of both these protocols, sets forth the timing and frequency of Semi-Annual Assessments in the form of Relative Accuracy Test Audits (RATAs) for RECLAIM Continuous Emission Monitoring Systems (CEMS). For instance, SOx and NOx equipment monitored by CEMS are required to perform RATAs on a semi-annual basis within six months of the end of the calendar quarter in which the CEMS last passed such a test. Such RATAs may be performed on an annual basis, provided that the relative accuracies of the SOx (NOx) pollutant concentration monitor, flow monitoring system, and the SOx (NOx) emission rate measurement system measured during the previous audit are 7.5% or less. These stringent testing requirements help ensure the accuracy of the CEMS in monitoring SOx and NOx emissions.

RATAs are conducted while the equipment is in operation. Equipment monitored by CEMS at some RECLAIM facilities, however, may experience extenuating circumstances that prevent them from conducting RATA tests in a timely manner. For instance, a major source may experience unforeseen equipment failure that renders it inoperable. Under such unforeseen events, the equipment cannot be made operational to conduct a RATA.

Additionally, facilities under contract with the California Independent System Operator (CalISO), as well as electrical generating facilities owned and operated by municipalities, have experienced difficulties in meeting RATA deadlines because their equipment operates based on current energy demand and may not operate long enough (or at all) to conduct a RATA in the quarter in which the RATA is due. In contrast, most facilities typically require their major sources to be continually operational, used on a regular basis, and able to conduct a timely RATA for their equipment. In the event that their equipment is not in operation, the facility has the option of seeking a variance or filing an application for non-operational status to avoid violating the RATA requirement since sources permitted as non-operational are not required to conduct RATAs. However, electrical generating facilities with equipment under contract with CalISO or owned and operated by municipalities often do not know when demand for electricity will result in generation equipment being required to operate until a day prior, creating scheduling difficulties in conducting RATAs and precluding the use of non-operational status. The inherent inconsistent operational nature of such equipment at electric generating facilities sometimes causes a need to postpone their RATAs.

Under current rule requirements, facilities having such extenuating circumstances seek variances for indeterminate amounts of time. The proposed amendments would, under specific conditions, allow RECLAIM Facility Permit Holders of equipment experiencing these extenuating circumstances to postpone RATAs. In the case of unforeseen equipment failure, Facility Permit Holders would have the option to postpone RATAs for this equipment to no more than 14 operating days after recommencing operation of the repaired equipment. Concerns were expressed that 14 operating days may not be sufficient in cases of sequential failures of the same equipment. However, the proposed 14 operating day RATA postponement for unforeseen equipment failure would apply separately for each unrelated, independent event. As such, if equipment operating under the 14 day RATA postponement provision should experience an unrelated failure prior to successfully completing a RATA, the 14 day clock would restart. On the other hand, if the same failure should recur in a similar situation, the 14 day clock would continue running and would not be reset. In the case of electrical generating facilities under contractual obligation with CalISO to have equipment available or owned and operated by municipalities that did not operate long enough to conduct a RATA during the quarter in which it is due, the semi-annual or annual assessment could be postponed to the next calendar quarter provided the follow criteria are met:

- The RATA was scheduled for the first 45 days of the calendar quarter in which it is due, but the equipment's operating schedule prevents completion of the RATA; and

- A passing Cylinder Gas Audit is conducted during the calendar quarter in which the RATA is due.

Paragraph 2, Subdivision B, Attachment C, of Appendix A to both Rule 2011 and Rule 2012 establishes both the timeline and the frequency for Semi-Annual Assessments to be performed for equipment monitored by CEMS. The purpose of these stringent testing requirements is to ensure the accuracy of the CEMS in monitoring SOx and NOx emissions. These Semi-Annual Assessments obligate facility permit holders to conduct RATAs within six months of the end of the calendar quarter in which the CEMS was last tested. Alternatively, such RATAs may be performed on an annual basis, provided that the relative accuracies of the SOx (NOx) pollutant concentration monitor, flow monitoring system, and the SOx (NOx) emission rate measurement systems are all 7.5% or less. Furthermore, for CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments may be delayed until no later than 14 operating days after emissions pass through the stack/duct. Some RECLAIM facilities that have had to disconnect their equipment due to failures and remove it off-site for repair have requested to have their RATA due dates extended. Other RECLAIM facilities, specifically electrical generating facilities that either have contractual agreements with CalISO to have their equipment available but not necessarily operating or are owned and operated by municipalities, have requested to delay their RATA testing until they have sufficient operating hours to conduct a RATA. Staff proposes to revise Attachment C. B.2. of Appendix A in both Rules 2011 and 2012 by adding subparagraphs (c) and (d), to allow RATA postponements due to these extenuating circumstances. For facilities that have major sources that are physically unable to operate to conduct a RATA, postponement of the RATA due date to within 14 unit operating days from the first re-firing of the major source is proposed to be allowed only if the following requirements are met:

- All fuel feed lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and

- The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, SOx (NOx) emissions would be required to be calculated using the maximum valid hourly emissions from the last 30 days of operation. Additionally, prior to equipment restart the Facility Permit Holder would be required to:

- provide written notification to the District no later than 72 hours prior to starting up the major source;

- start the CEMS no later than 24 hours prior to the start-up of the major source; and

- conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source.

CEMS emissions data after the re-start of operations would only be considered valid if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data would be considered invalid until the semi-annual or annual assessment is performed and passed. For such invalid CEMS emissions data, SOx (NOx) emissions would be calculated using the maximum valid hourly emissions from the last 30 days of operation, commencing with the hour of startup and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

For electrical generating facilities either having contractual agreements with CalISO to have their major source available but not necessarily operating, yet not having sufficient hours to conduct RATA testing or owned and operated by a municipality, amended rule language is being proposed to allow the postponement of the semi-annual or annual assessment to the next calendar quarter, provided that the facility demonstrates:

- the semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due but the assessment was not completed due to lack of adequate operational time, and

- a Cylinder Gas Audit (CGA) is conducted and passed within the calendar quarter when the assessment is due.

Rules 2011 and 2012 - Typographical Edits

The staff proposal would, if adopted, also make the following typographical clarifications and corrections:

- Under Rules 2011 and 2012 Appendix A, Attachment C B.2.b the word “unit” would be added to offer clarity regarding the time period for RATAs that are conducted on equipment for which no emissions have passed through any stack or duct in two or more successive quarters;

- The rule language “Proposed” and “Draft” found in Rule 2011 Appendix A, Attachment C B.2.e., which inadvertently had been left in the previous amended rules, would now be deleted;

- Rule language found in subparagraph (e) of Rule 2012 Appendix A, Attachment C B.2, referencing “Chapter 2, Subdivision B, Paragraph 10, Chapter 2, Subdivision B, Paragraph

11, and Chapter 2, Subdivision B, Paragraph 12" would be replaced with "Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 18", to clarify relative accuracy requirements for fuel flow measuring devices; and

- Rule language found in subparagraph (e) of Rule 2011 Appendix A, Attachment C B.2 referencing "Chapter 2, Subdivision B, Paragraphs 10, 11, and 12…" would be replaced with "Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 13…" to clarify the relative accuracy requirements for analyzers.