Proposed Rule 1179.1

NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

Working Group Meeting #4

Date: February 12, 2020

Conference call #: 1-866-705-2554

Passcode: 220103

Agenda

- Summary of last working group meeting
- Public Comments
- Applicability
- BARCT assessment
  - Microturbines
  - Boilers ≤ 2 mmbtu/hr
  - Boilers > 2 mmbtu/hr
  - Turbines

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Summary of Last Working Group Meeting

- Applicability
  - Engine applicability and associated fees with including engines
    - Engine survey
  - Boilers, turbines, and microturbines located at POTWs that fire either natural gas and/or digester gas
- Technology Assessment
  - Control technologies and gas treatment systems
  - Application of technologies
  - Feasibility of NOx emission levels with technologies
  - Proposed initial NOx limits for boilers >2 mmbtu/hr and turbines
- Listed sources for obtaining cost information

Comments Made at Working Group Meeting #3

Stakeholders commented:	South Coast AQMD responses:
Fees for permit revisions for engines can be waived	South Coast cannot guarantee that the Governing Board will waive fees
Future working group meeting should focus on costs and cost effectiveness	Working group meeting #4 will focus on costs and cost effectiveness
One facility is experiencing damage to burners on their digester gas boilers	Issue appears to be specific to one facility Seeking input from other facilities

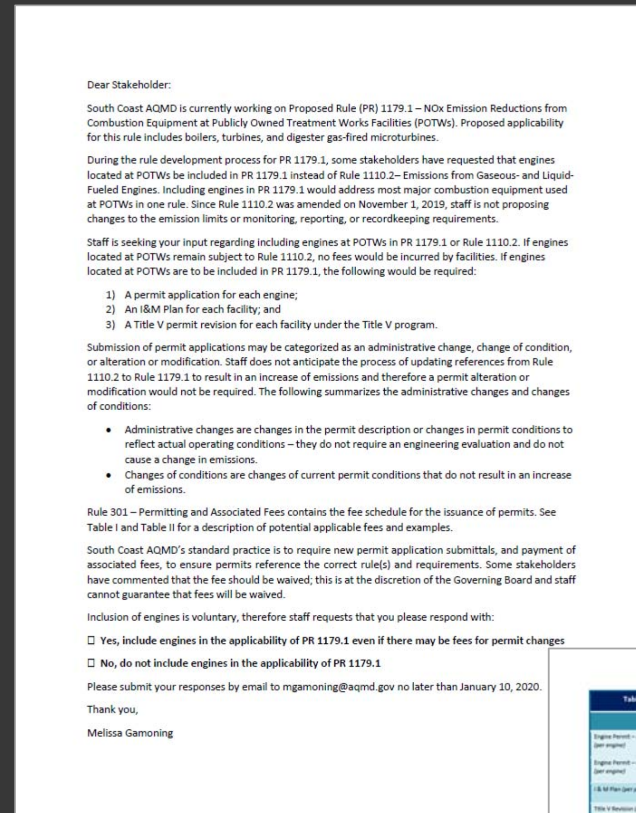
Comments Made at Working Group Meeting #3 *(continued)*

Stakeholders commented:	South Coast AQMD responses:
Boiler results did not include results at low and high loads (only average loads presented)	Staff will present source test results for all loads that boilers were tested at
Do not agree that the Biogas Toolkit is an accurate source for cost information	Biogas toolkit information will not be used to obtain cost information. Costs for gas treatment systems will rely on information from facilities and suppliers.

Applicability

Engines – Survey Results

- Staff sent a survey out on December 12, 2019 to all POTWs with engines to determine the consensus of including engines in the applicability of PR 1179.1
- 8 agencies (12 facilities) had a biogas or natural gas engine
  - 6 agencies are in favor of including only biogas engines
  - 1 agency that has 5 natural gas engines is in favor of including engines
  - 1 agency that has one natural gas engine is not in favor of including engines



Dear Stakeholder:

South Coast AQMD is currently working on Proposed Rule (PR) 1179.1 – NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities (POTWs). Proposed applicability for this rule includes boilers, turbines, and digester gas-fired microturbines.

During the rule development process for PR 1179.1, some stakeholders have requested that engines located at POTWs be included in PR 1179.1 instead of Rule 1110.2– Emissions from Gaseous- and Liquid-Fueled Engines. Including engines in PR 1179.1 would address most major combustion equipment used at POTWs in one rule. Since Rule 1110.2 was amended on November 1, 2019, staff is not proposing changes to the emission limits or monitoring, reporting, or recordkeeping requirements.

Staff is seeking your input regarding including engines at POTWs in PR 1179.1 or Rule 1110.2. If engines located at POTWs remain subject to Rule 1110.2, no fees would be incurred by facilities. If engines located at POTWs are to be included in PR 1179.1, the following would be required:

1) A permit application for each engine;
2) An I&M Plan for each facility; and
3) A Title V permit revision for each facility under the Title V program.

Submission of permit applications may be categorized as an administrative change, change of condition, or alteration or modification. Staff does not anticipate the process of updating references from Rule 1110.2 to Rule 1179.1 to result in an increase of emissions and therefore a permit alteration or modification would not be required. The following summarizes the administrative changes and changes of conditions:

- Administrative changes are changes in the permit description or changes in permit conditions to reflect actual operating conditions – they do not require an engineering evaluation and do not cause a change in emissions.
- Changes of conditions are changes of current permit conditions that do not result in an increase of emissions.

Rule 301 – Permitting and Associated Fees contains the fee schedule for the issuance of permits. See Table I and Table II for a description of potential applicable fees and examples.

South Coast AQMD's standard practice is to require new permit application submittals, and payment of associated fees, to ensure permits reference the correct rule(s) and requirements. Some stakeholders have commented that the fee should be waived; this is at the discretion of the Governing Board and staff cannot guarantee that fees will be waived.

Inclusion of engines is voluntary, therefore staff requests that you please respond with:

☐ **Yes, include engines in the applicability of PR 1179.1 even if there may be fees for permit changes**

☐ **No, do not include engines in the applicability of PR 1179.1**

Please submit your responses by email to mgamoning@aqmd.gov no later than January 10, 2020.

Thank you,

Melissa Gamoning

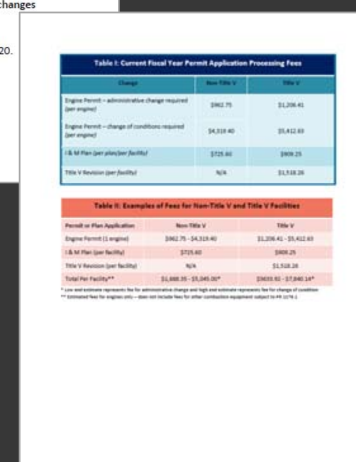


Table I: Current Fiscal Year Permit Application Processing Fees

Change	Non-Title V	Title V
Engine Permit – administrative change required (per engine)	$962.75	$1,206.41
Engine Permit – change of conditions required (per engine)	$4,319.40	$5,412.63
I & M Plan (per plan/per facility)	$725.60	$909.25
Title V Revision (per facility)	N/A	$1,518.28

Table II: Examples of Fees for Non-Title V and Title V Facilities

Permit or Plan Application	Non-Title V	Title V
Engine Permit (1 engine)	$962.75 - $4,319.40	$1,206.41 - $5,412.63
I & M Plan (per facility)	$725.60	$909.25
Title V Revision (per facility)	N/A	$1,518.28
Total Per Facility**	[illegible]*	[illegible]*

Staff Recommendation for Engines

- Natural gas engines
  - 4 out of 5 facilities with natural gas engines responded that they prefer that natural gas engines remain in Rule 1110.2
  - Staff recommendation: Natural gas engines will remain in Rule 1110.2
- Biogas engines
  - All facilities with biogas engines responded that they prefer that biogas engines be included in Proposed Rule 1179.1
  - Staff recommendation:
    - Include biogas engines in Proposed Rule 1179.1
    - Provisions in Rule 1110.2 (emission limits, averaging times, monitoring, reporting, and recordkeeping requirements) will be incorporated in Proposed Rule 1179.1
    - Considering implementation timeframe to revise permit – possibly 2 to 3 years

BARCT Assessment

BARCT Assessment – Small boilers ≤ 2 mmbtu/hr and Microturbines

- Previous working group meetings focused on the technology assessment and initial NOx emission limits for boilers > 2 mmbtu/hr and turbines
- Presenting BARCT assessment for microturbines
  - Technology assessment
  - Initial NOx emission limit
  - Cost-Effectiveness
  - Propose NOx BARCT emission limits
- Beginning BARCT assessment for small boilers ≤ 2 mmbtu/hr

BARCT Assessment – Boilers > 2 mmbtu/hr and Turbines

- Previous working group meetings focused on the technology assessment
  - Low NOx burners, SCR, and gas treatment
- Proposed initial NOx emission limits
  - Boilers retrofit with low NOx burner
  - Turbines retrofit with SCR and implementing gas treatment
- Continuing with BARCT assessment
  - Technology assessment and propose initial NOx emission limit
    - Boilers retrofit with SCR
    - Turbine replacement
  - Cost-effectiveness and propose NOx BARCT emission limits

Progress of BARCT Assessment

Equipment Category	Assessment of South Coast AQMD Regulatory Requirements	Assessment of Emission Limits for Existing Units	Other Regulatory Requirements	Assessment of Pollution Control Technologies	Initial BARCT Emission Limits and Other Considerations	Cost-Effectiveness Analysis	BARCT Emission Limits
Microturbines							
Boilers ≤2 mmbtu/hr	✓						
Boilers >2mmbtu/hr	✓	✓	✓	✓	✓		
Turbines	✓	✓	✓	✓	✓		

BARCT Analysis for Microturbines and Boilers ≤ 2 mmbtu/hr

Microturbines (Digester Gas)

- A microturbine is a turbine that is < 0.3 MW
- Currently no rule for microturbines at South Coast AQMD
- Rule 219 allows microturbines ≤ 3.5 mmbtu/hr (total output < 2 MW) to be exempt from permitting provided that a filing pursuant to Rule 222 is submitted; and:
  - Microturbines were in operation prior to May 3, 2013; or
  - Microturbines were certified by the state of California at time of manufacture

Microturbine Universe

Two facilities have a total of 10 microturbines

Facility 1

- Five 0.03 MW turbines
- 100% digester gas fired
- Exempt from permitting – in operation prior to May 3, 2013

Facility 2

- Five 0.2 MW turbines
- Permitted to fire digester gas or a blend of digester gas and natural gas
- Not yet in commission

Microturbines Technology Assessment

- Limited source test information from facilities and supplier
  - 1 source test result of 1.25 ppm
- Supplier can guarantee 9 ppm with proper maintenance and gas treatment
  - 9 ppm achievable with varying loads and HHV
- Gas treatment required for digester gas use
  - Published limit for siloxanes is < 5 ppb (real operations show that higher levels are permissible)
- Control technology
  - Uses a lean premix
  - Addition of SCR difficult due to low exhaust temperature

Initial NOx Limit for Microturbines

Proposed limit for microturbines that fire digester gas or a blended fuel with digester gas

South Coast Rule Limit	Existing Units (source tests)	Other Regulatory Requirements	Technology Assessment	Initial NOx Limit	Proposed BARCT NOx Limit
Turbines < 0.3 MW	**Permitted at 9 ppm**	**1.25 ppm**	**No known rule limits or permitted digester gas microturbines**	**9 ppm**	**9 ppm**	**9 ppm** (Units in operation meeting limit)

Cost-effectiveness analysis not conducted since existing sources are meeting the Proposed BARCT NOx Limit

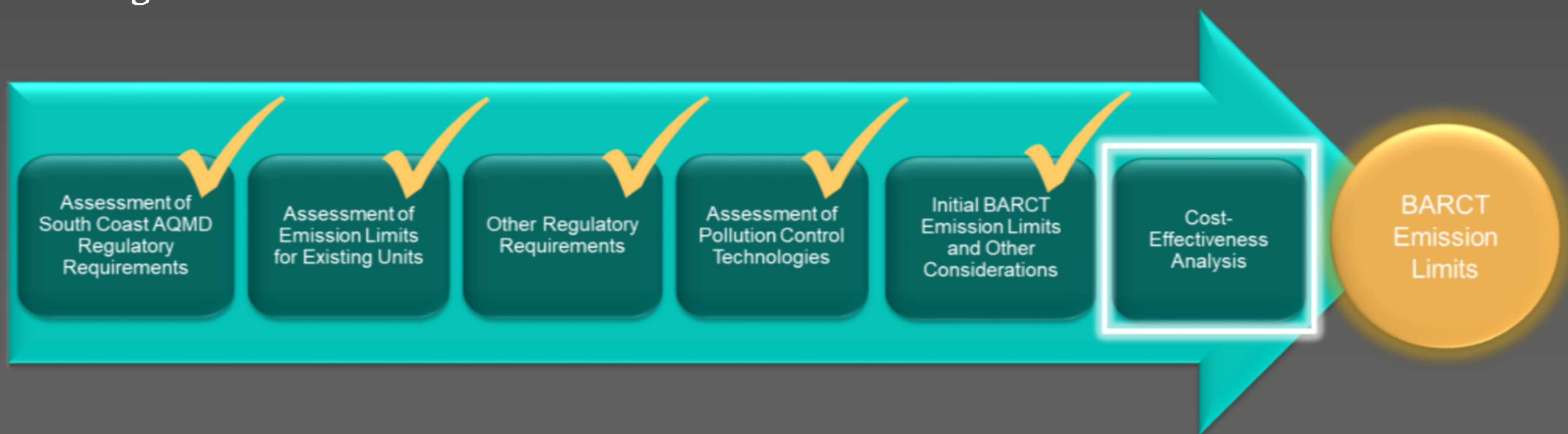
Boilers ≤ 2 mmbtu/hr – Digester Gas

- Currently no rule at South Coast AQMD for boilers ≤ 2 mmbtu/hr that fire digester gas
- 12 boilers that range from 0.75 mmbtu/hr – 1.95 mmbtu/hr
  - 10 permitted at 30 ppm
  - 2 permitted at 6 lbs/day
- Staff is assessing the differences between boilers greater than and less than 2 mmbtu/hr
  - Conducting technology assessment to understand if burners that can meet 9 ppm are available for boilers ≤ 2 mmbtu/hr

Cost-Effectiveness Methodology and Assumptions

Overview

- Cost-effectiveness analysis is conducted on the initial BARCT emission limit
- Cost-effectiveness is the cost (capital plus annual operating costs) over the emission reductions for the life of the equipment
- Staff uses the 2016 AQMP cost-effectiveness threshold of $50,000 per ton of NOx reduced as guidance for establishing the BARCT limit



BARCT

California H&SC §40406 defines BARCT as:

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

- Includes a technology assessment and cost-effectiveness analysis
- Applicable to equipment retrofits and replacement

Cost-Effectiveness Calculation

- Threshold is $50,000/ton NOx reduced
- Calculated using Discounted Cash Flow Method
  - Cost Effectiveness = Present Value / Emissions Reduction Over Equipment Life
  - Present Value = Capital Cost + (Annual Operating Costs * Present Value Formula)
  - Present Value Formula = $(1 - 1/(1 + r)n)/ r)$
    - $r = (i - f)/(1 + f)$
    - i = nominal interest rate
    - f = inflation rate

Elements Included in Capital and Annual Operating Costs

Capital Costs

- Equipment needed to achieve the initial BARCT limit
- Installation (includes construction)

Annual Costs

- Labor
- Maintenance
- Electricity
- Catalyst (turbine only)
- Reagent (turbine only)
- Gas treatment media (turbine only)
- Testing

Other Cost Considerations

Stranded Assets

- Accounts for costs associated with the replacement of equipment before the equipment life
  - Equipment age based on either the permitted or installation date
- Cost analysis accounted for stranded assets for new equipment replacements
- Additional cost calculated by:
  - $Stranded\ Assest\ Cost = \left(\frac{Equipment\ Life - Existing\ Equipment\ Age}{Equipmen\ Life}\right) * (\text{Existing}\ Equipment\ Cost)$
  - $Total\ New\ Equipment\ Cost = (New\ Equipment\ Cost) + (Stranded\ Asset\ Cost)$

Nominal Interest Rate

- 4%

Other Cost Considerations *(continued)*

Updated Slide

Equipment Life

- Burners = 15 years
- Turbines = 25 years
- SCR = 25 years
- Gas treatment system = 25 years

Equipment Replacement

- Equipment replacement is normal component of business operations
  - Replacing equipment after equipment life is not expected to add any additional cost
  - No additional operating & maintenance costs for replacing equipment with similar equipment

Estimated Emission Reductions

- Emission reductions calculated over same timeframe as equipment life
- Reductions only calculated for units with source test results or permit limits above the initial BARCT limits

Baseline NOx Concentration

↓

Use NOx concentration from source test results if available

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If source test results not available, use permitted NOx limit

Baseline Throughput

↓

Use actual throughput reported in Annual Emissions Report (AER) if available

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If no AER data, use scaled average throughput for unit's specific source category

Cost-Effectiveness Analysis

Implementation Approach for Retrofit or Replacement

Updated Slide

Overall Goal

- Apply emission limit to equipment via the most cost-effective schedule
- Staff aimed to reduce stranded asset costs and only require replacement when cost-effective to do so

Two Compliance Scenarios

1. Fixed-Date: Emission limit effective at a set point in time
2. Phase-in: Emission limit effective upon replacement

Proposed Compliance and Cost-Effectiveness Approach

Updated Slide

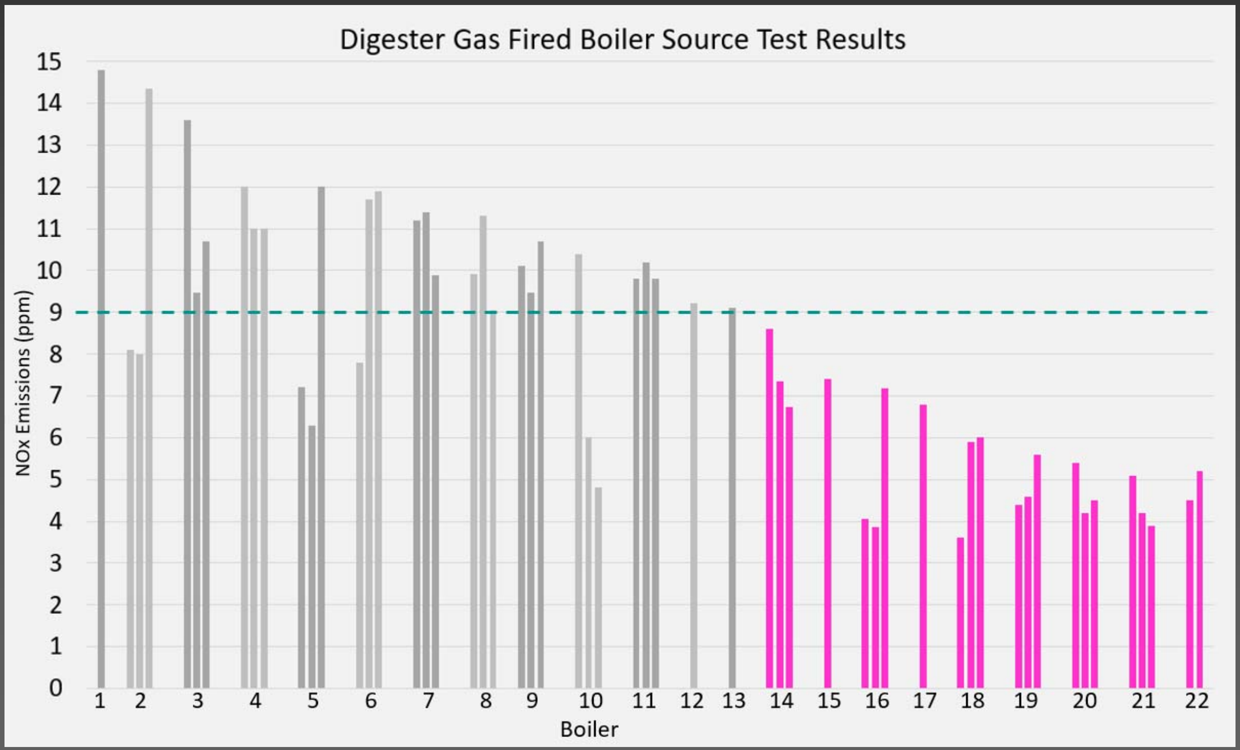
Fixed-Date Approach Comply by fixed-date	▪ Emission limit effective on a fixed-date
Phase-in Approach Comply upon replacement	▪ Emission limit effective when burner or unit is replaced

- Evaluated cost-effectiveness for all units
- Considerations for a fixed-date or a phase-in approach are based on:
  - Average cost-effectiveness
  - Financial challenges for essential public services
  - Operation and maintenance of equipment

Boilers > 2 mmbtu/hr

Source Test Results for Boilers Firing Digester Gas

- Stakeholders commented that all boiler source test results were not represented for all loads in previous working group meeting
- Analyzed all source test results
  - Low, mid, high loads are shown respectively*
  - 9 out of 22 boilers meet 9 ppm for all their source test results
  - 6 boilers meeting NOx emissions as low as 7 ppm
    - Using new and retrofit burners



* Some boilers were only tested at mid loads. One boiler was tested at low and mid load.

Cost-Effectiveness of NOx Limit of 9 ppm (Retrofit Boiler with Low NOx Burners)

Updated Slide

- Cost-effectiveness excluded units that already meet 9 ppm
- Average cost-effectiveness >>$50,000 per ton of NOx reduced
  - No capital and annual cost increase assumed to implement burner that can meet 9 ppm
  - Associated costs solely from stranded assets
- It is not cost-effective to retrofit boilers with a burner that can meet 9 ppm if existing burner operations started less than 15 years ago

Staff recommendation: Meet 9 ppm at burner replacement

Cost-Effectiveness of NOx Limit of 5 ppm (Retrofit Boilers ≥ 20 mmbtu/hr with SCR)

Updated Slide

- Retrofitting boilers with SCR was analyzed for an initial NOx limit of 5 ppm that was determined feasible in the Rule 1146 series rulemaking
  - > 2 mmbtu/hr boiler universe ranges from 2.52 mmbtu/hr – 63.5 mmbtu/hr
- Cost-effectiveness was calculated for boilers ≥ 20 mmbtu/hr that do not meet 5 ppm
  - Average cost-effectiveness is over $1 million per ton of NOx reduced ◊ and exceeds the $50,000 per ton of NOx reduced threshold

Staff recommendation:

- Not cost-effective to retrofit boilers ≥ 20 mmbu/hr to meet 5 ppm
- Boilers ≥ 20 mmbu/hr to meet 9 ppm at burner replacement

◊ SCR requires a gas clean up system. Cost of gas clean up was not included in the cost-effectiveness for SCR retrofits.

Turbines

New Turbine Technology Assessment

- Turbines manufactured after year 2000 are in the 4-25 ppm range when firing natural gas
- Use of digester gas may affect NOx emissions and turbine suppliers warranty higher NOx levels for biogas than natural gas
- Turbine performance in real world applications:
  - 10 turbines in use at landfills without SCR
    - Source test results that range 3.1 ppm – 7.6 ppm
    - Gas treated prior to combustion in turbine
- Staff proposes that initial limits for turbines at landfills can apply to new turbines at POTWs
  - Initial NOx limit = 12.5 ppm

Initial NOx Limits for Turbine Replacement

	South Coast Rule Limit	Existing Units (source tests)	Other Regulatory Requirements	Technology Assessment	Initial NOx Limit	Proposed BARCT NOx Limit
BARCT Assessment Results	**Only permit limits apply (12.5 – 25ppm)**	**< 10 ppm** (landfill units)	**3 – 15 ppm**	**< 10–25 ppm**	**12.5 ppm**	Need to conduct cost-effectiveness on initial BARCT NOx limit

Emissions from this category are the largest in the POTW universe.
Total NOx emission for 6 digester turbines is 0.25 tpd

Staff will continue to explore turbine replacement options

NOx Limits To Be Evaluated

- Cost-effectiveness evaluated for three NOx limits that can be achieved by different methods

SCR + gas treatment

Reduce NOx emissions to 2.5 ppm

Based on technology assessment presented last working group meeting

Water injection

Reduce NOx emissions to 18.8 ppm

Based on facility claim during Rule 1134 rulemaking

Replacement

Reduce NOx emissions to 12.5 ppm

Based on technology assessment – presented in this working group meeting

Obtaining Costs

- Staff obtained costs from facilities, suppliers, and cost estimating tools

SCR

- Facilities
- EPA Cost Manual Spreadsheet
- Engineering consultants
- Catalyst supplier

Gas Treatment

- Facilities
- Gas treatment supplier

Water Injection

- Facility
- Demineralized water supplier

Turbine Replacement

- Facility
- EPA Manual for CHP Technologies

SCR Costs

- Assumptions for EPA Cost Manual for SCR and supplier estimates:
  - HHV = 665 Btu/scf
  - Number of days operating = 365
  - Inlet NOx = 22 ppm
  - Removal efficiency = 90%
  - Operating life of catalyst = 24,000 hours
  - Equipment life = 25 years
  - Design = 5 ppm NH_3 slip (19% aqueous)
  - Inlet temperature = 866F
  - Electricity = $0.19/kwh - $0.25/kwh

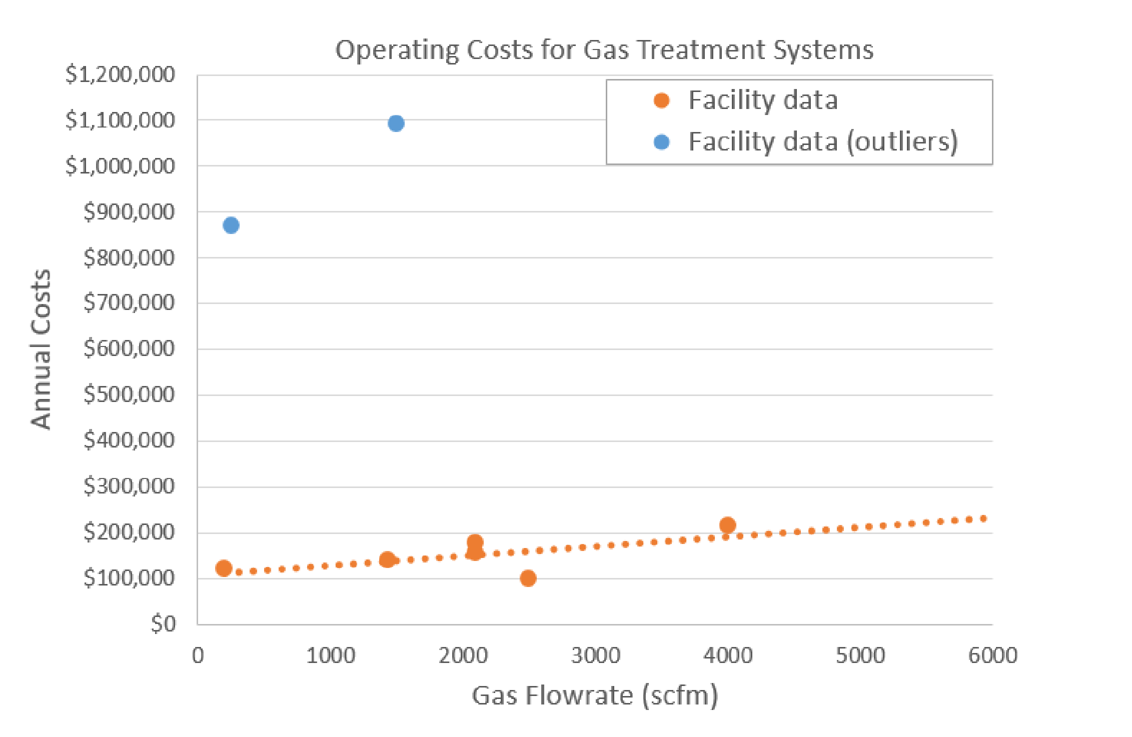
Source	Capital Cost	Annual Costs
EPA Cost Manual for SCR	$8.3 million (3 SCRs)	$1.2 million (3 SCRs)
Supplier A	$8.0 million (3 SCRs)	$489,500 (3 SCRs)
Supplier B	$2.5 million* (3 SCRs)	$450,000 (3 SCRs)
Rule 1110.2 staff report	$1.4 million-$6.6 million (3 SCRs)	EPA Cost Manual
Facility A	Unavailable	$38,000 (3 SCRs) new, no catalyst replacement
Facility B	Unavailable	$48,000 (5 SCRs) new, no catalyst replacement
Average cost for 3 SCRs	$7.6 million	$458,500

* Not included in average cost.

^ Average costs adds $33,300/year for Facility A and Facility B for catalyst costs

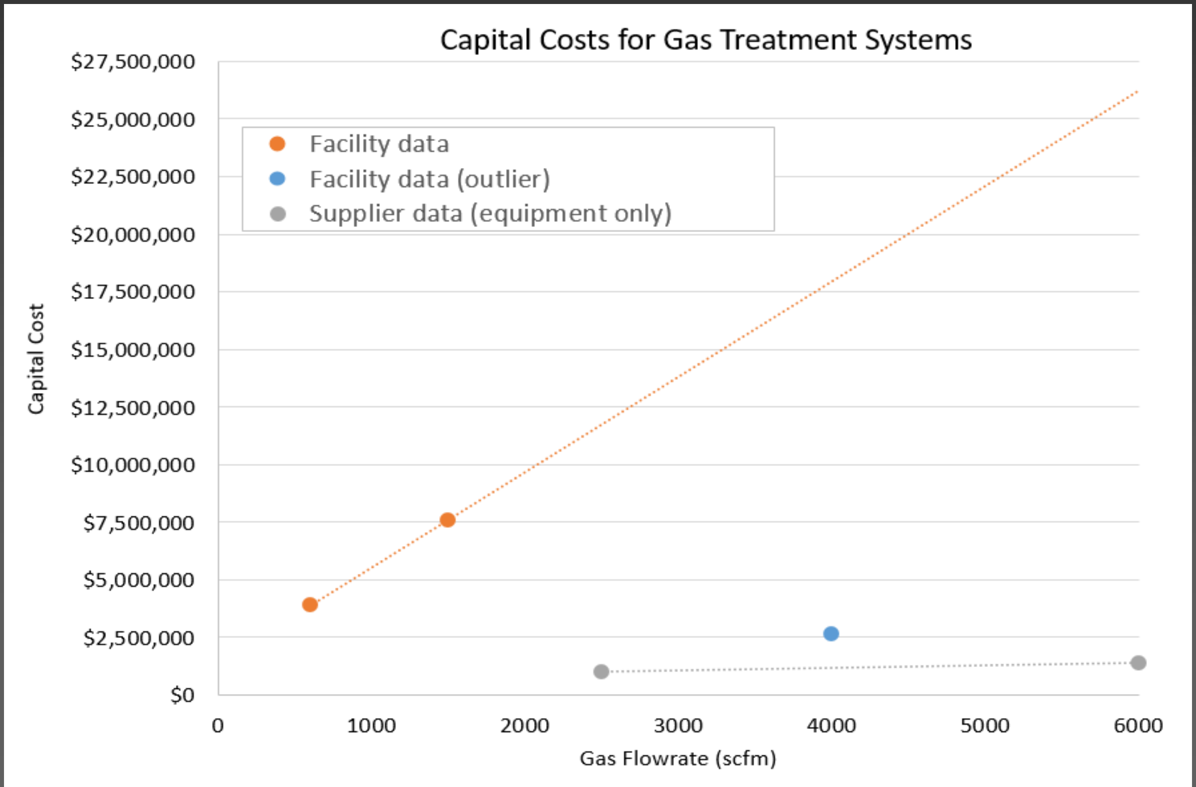
Gas Treatment Costs – Annual

- Obtained annual costs from 8 facilities
  - All costs obtained from facilities that use SCR
- Siloxane levels for these facilities range from 4.4 ppmv to 15 ppmv
- Gas treatment systems designed to remove siloxane levels to less than <100 ppb
  - One facility treated digester gas to pipeline quality gas – has highest operating costs



Gas Treatment Costs – Capital

- Obtained capital costs from 3 facilities
- Obtained equipment only costs from one supplier
- Costs assume a gas treatment system that will achieve <100 ppb siloxane level with inlet siloxane levels at <10 ppm



Costs for Increasing Water Injection

- Facility has stated that they can meet 18.8 ppm with doubling the amount of injected demineralized water
  - Increase of 5,000 – 8,000 gallons per turbine per day
- Facility estimated that the cost of demineralized water is about 10x the cost of potable water
- Staff received cost estimate from supplier for 24,000 gallons per day to meet the needs of 3 turbines

Source	Cost of Demineralized Water	Annual Cost per Turbine
Facility	$0.07 per gallon (10x cost of regular water)	$204,400
Demineralized water supplier	$0.0281 per gallon	$82,052

Costs for Replacement

- Staff obtained costs for new turbines from an EPA publication and one landfill facility

Source	Capital Cost	Annual Costs
EPA Catalog of CHP Technologies	\$1.2 – \$1.5 million/MW	\$0.0092 - \$0.0093/kWh
Facility A	\$8.7 million (3 turbines) \$21 million (installation + CEMS)	\$100,000 per turbine

Cost-Effectiveness to Meet 2.5 ppm with SCR + Gas Treatment

Retrofit with SCR + Implement Gas Treatment

- Cost-effectiveness to retrofit three existing turbines with SCR and implement gas treatment technology that processes 6000 scfm of digester gas

System	Capital Cost	O&M Cost	Emission Reductions (25 years)	Cost-effectiveness ($/ton of NOx reduced)
Gas treatment	$26,250,000	$250,000	1,480 tons	$30,400
SCR	$7.6 million	$470,000		

Cost-Effectiveness to Meet 18.8 ppm with Increased Water Injection

Increase Water Injection

- Cost-effectiveness to increase water injection rates on existing turbines

Source	Cost of Demineralized Water	Annual Cost per Turbine	Emission Reductions (25 years)	Cost-effectiveness for 3 Turbines ($/per ton of NOx reduced)
Facility	$0.07 per gallon (10x cost of regular water)	$204,400	239 tons	$40,050
Demineralized water supplier	$0.0281 per gallon	$82,052		$16,077

Average Cost Effectiveness
$28,064

Cost-Effectiveness Analysis to Meet 12.5 ppm with Turbine Replacement

Replacement

- Cost-effectiveness to replace 3 turbines with 6 smaller turbines that can meet 12.5 ppm
  - Gas treatment may not be required – lower levels of gas treatment than that required for SCR may be permissible

System	Capital Cost	O&M Cost	Emission Reductions (25 years)	Cost-effectiveness ($/ton of NOx reduced)
New Turbines	$45 million	$600,000	600 tons	$90,500

BARCT Analysis Summary

New Slide

	Assessment of South Coast AQMD Regulatory Requirements	Assessment of Emission Limits for Existing Units	Other Regulatory Requirements	Assessment of Pollution Control Technologies	Initial BARCT Emission Limits and Other Considerations	Cost-Effectiveness Analysis	BARCT Emission Limits
NOx Limit 18.8 ppm (water injection)	**18.8 – 25 ppm (permit limits)**	**2.5 – 22 ppm**	**3 – 15 ppm**	**< 2.5 ppm**	**2.5 ppm**	**< $50,000 per ton of NOx reduced**	**18.8 ppm**
NOx Limit 2.5 ppm (SCR)							**2.5 ppm (at replacement)**

Rulemaking Schedule

4-6 weeks	2nd Quarter 2020	3rd Quarter 2020	3rd Quarter 2020
Next Working Group Meeting	Public Workshop	Set Hearing	Public Hearing

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