Rule 1109.1 – NOx Emission Reduction for Refinery Equipment

Working Group Meeting #8

June 27, 2019

Call-in Information

Call-in Number: 1-888-450-5996

Meeting Number: 282645

Agenda

- Summary of Working Group Meeting #7
- Progress of Rule Development
- Third Party Consultant Update
- CEMS Data
- SCR Cost Model Update and Revisions
- Next Steps

Progress of Rule Development

Summary of Working Group #7 (4/30/19)

- Presented meetings with technology manufacturers
- Discussed U.S. EPA Selective Catalytic Reduction (SCR) Cost Model
- Proposed initial considerations for rule concepts

Since Last Working Group Meeting

- Finalizing both contracts with Norton Engineering Consultants, Inc. (Norton) and Fossil Energy Research Corporation (FERCo)
- Continued meetings and conversations with control technology suppliers
- Follow-up site visit to facilities to address additional concerns
- Completed CEMS data analysis
- U.S. EPA SCR cost model revisions/updates
  - Discussion with EPA regarding SCR cost model methodology
  - Requesting additional cost information from stakeholders
- RECLAIM staff is currently working on NSR/BACT resolution and will provide further updates

Third Party Consultant Update

Third Party Consultant Update

- Finalizing contracts with:
  - Norton
  - FERCo
- Initial meetings with each consultant scheduled in July
- Consultants will perform separate tasks

NORTON engineering

- Review staff’s BARCT analysis
- Research international low-NOx installations (achieved in practice)
- Control technologies
- Costs

FERCo FOSSIL ENERGY RESEARCH CORPORATION

- Difficult installations and/or retrofits
  - Space constraints
  - Burner technology installations
  - SCR and ammonia injection grid optimization

Proposed Scope of Work

Norton Engineering
Task 1: Assess the feasibility of staff's proposed NOx limits and secondary pollutant limits for affected equipment
Task 2: Assess the cost effective estimates including, but not limited to the use of the U.S. EPA SCR cost model
Task 3: Provide recommendations on the technological and/or cost feasibility of affected equipment
Task 4: Communicate, when warranted, with the other consultant evaluating the potential installation challenges, or with vendors of control technology
Task 5: Prepare progress status updates and final report including technology and/or cost recommendations
Task 6: Present findings at meeting(s)

Fossil Energy Research Corporation
Task 1: Conduct potential facility visits to make detailed on-site observations and engineering evaluations of affected equipment
Task 2: Feasibility of installation, including but not limited to, feasibility of installation of new control technologies
Task 3: Determine if further optimization can be performed on currently installed NOx control systems to help achieve further emission reductions
Task 4: Prepare progress status updates and final report including recommendations
Task 5: Present findings at meeting(s)

CEMS Data

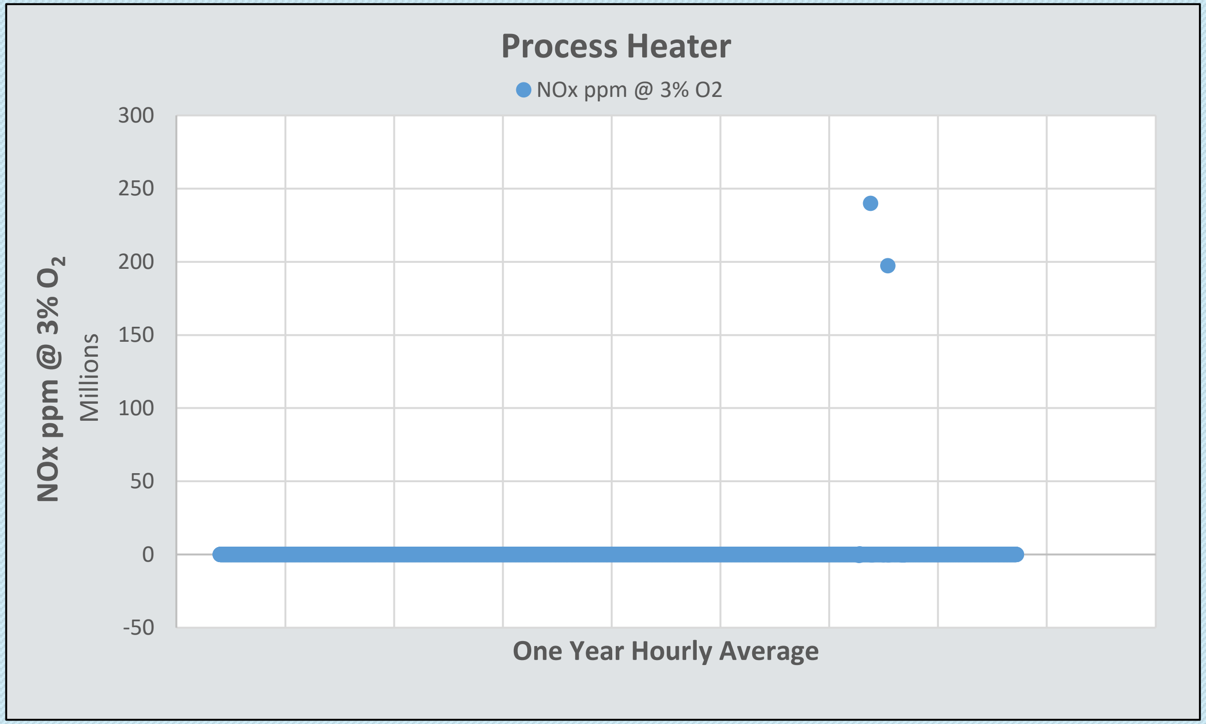
Purpose for CEMS Data Collection

- 2018 refinery survey only included annual average emissions for each unit
  - Does not reflect day-to-day concentration variations, nor operational peak
- CEMS data provides a range of real time data that better characterizes equipment emissions
- Staff requested the following CEMS data from facilities:
  - Hourly average NOx in ppm
  - Hourly average O_2 in percent
  - Hourly average fuel flow rate and higher heating value (HHV)
- CEMS data will provide estimated operational peak NOx concentration for units with no permit limit
  - Most units >40 MMBTU/hr do not have a NOx concentration permit limit
- Operational peak NOx concentration will be used to calculate emission reduction potential and cost-effectiveness for each unit

CEMS Data Evaluation

- Evaluate CEMS data to eliminate anomalies that can skew data
- Excluded obvious outlying data such as missing, negative, and very high values
- Established "normal" operational parameters to help identify other outlying data points
- Normal operational parameters were determined from:
    - Fuel flow rate trends
    - Measured O_2 trends
    - Length of time that trends occur
- Data points outside normal parameters may indicate "abnormal" conditions

Example CEMS Data



CEMS Data Parameter Considerations

Low fuel flow

- Could be start-up/shutdown conditions
- Only pilots are running
- May show extremely high NOx or low (*negative*) NOx emissions

High Higher Heating Value (HHV)

- May result in higher NOx emissions (*not necessarily a outlier*)

Low heater capacity or utilization

- BTU fired below 25% probably not normal operation

Range of measured O_2

- >19% O_2 with low fuel flow may indicate only pilots are running (start-up/shutdown)
- >15% O_2 further evaluation needed
- >10% O_2 with all other parameters in range, could indicate leaking firebox (*did not exclude*)
- <10% O_2 typical heater operation

Reasons for outliers

- Possible maintenance activity or turnaround conditions
- Possible processing unit upset conditions or start-up/shutdown conditions

CEMS Data Evaluation

Staff evaluated CEMS data for 134 heaters and boilers

Graphed NOx ppm data, corrected to 3% O_2

Identified obvious outliers

Estimated “Normal Operational Parameters” based on fuel flow, O_2, and heater capacity

Eliminated NOx data points outside of Normal Operational Parameters

Example Analysis for 52 MMBtu/hr Heater

Date/Time	Hourly O2 Conc. (%)	Hourly NOx Conc. (PPM)	Hourly NOx Conc. (PPM @3% O2)	Hourly Fuel Flow Rate (MSCF)	HHV of the Fuel (BTU/SCF)
Day 1, hour 0	6	26	32	29	1326
Day 1, hour 1	6	26	31	29	1331
Day 1, hour 2	6	26	32	29	1323
Day 1, hour 3	6	26	32	29	1351
Day 1, hour 4	6	26	31	29	1360
Day 1, hour 5	6	26	31	29	1340
Day 1, hour 6	6	26	31	29	1323
Day 1, hour 7	6	27	32	28	1359
Day 1, hour 8	6	27	32	28	1384
Day 1, hour 9	6	27	33	27	1402
Day 1, hour 10	6	27	32	27	1405
Day 1, hour 11	6	27	32	26	1406
Day 1, hour 12	6	26	32	27	1395
Day 1, hour 13	6	26	32	27	1390
Day 1, hour 14	6	26	32	27	1361
Day 1, hour 15	6	26	31	26	1416
Day 1, hour 16	6	26	31	26	1434
Day 1, hour 17	6	25	30	27	1413
Day 1, hour 18	6	25	29	28	1374
Day 1, hour 19	6	25	29	28	1361
Day 1, hour 20	6	25	30	28	1373
Day 1, hour 21	6	25	30	28	1368
Day 1, hour 22	6	25	30	28	1363
Day 1, hour 23	6	26	31	27	1377

Corrected NOx ppm data to 3% O_2

Range of Data

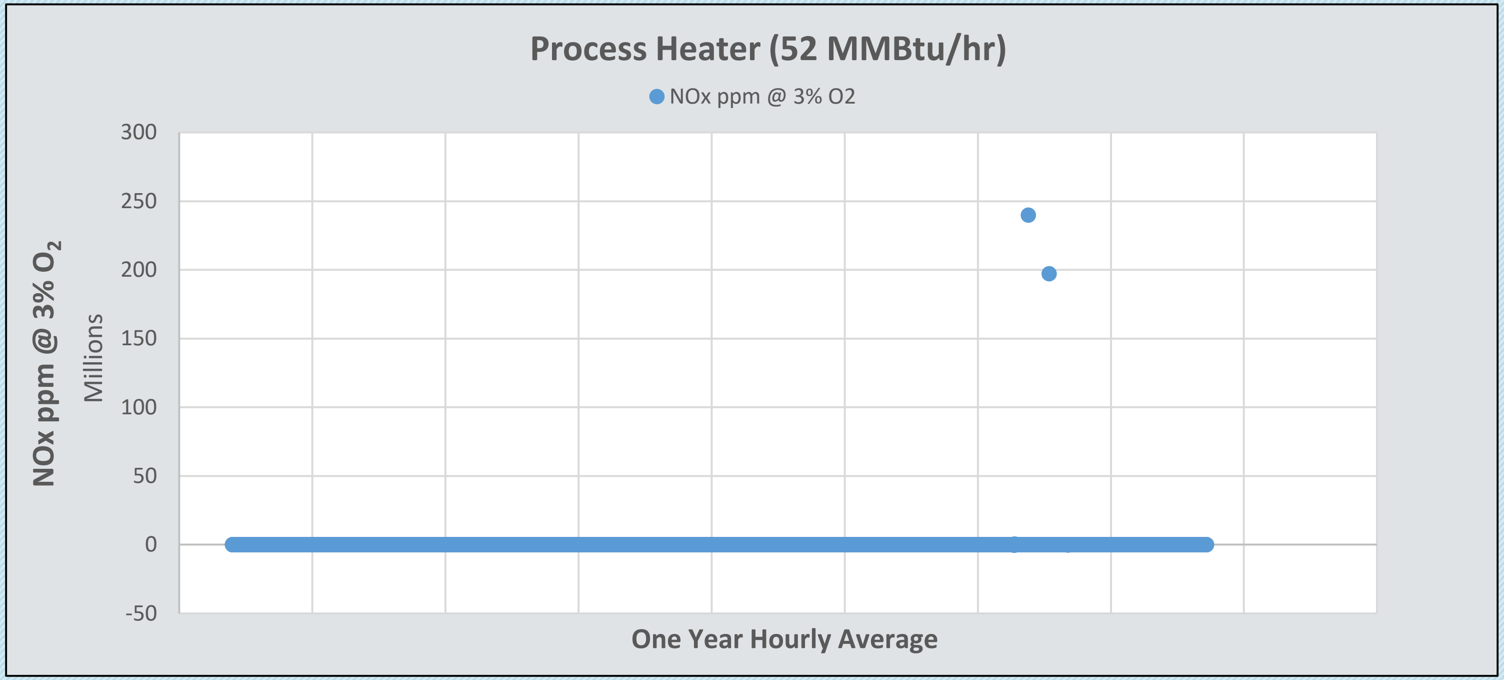
Corrected NOx: *-510,016 to 239,842,232 ppm*

Fuel flow rate: *0 to 37 MSCFH*

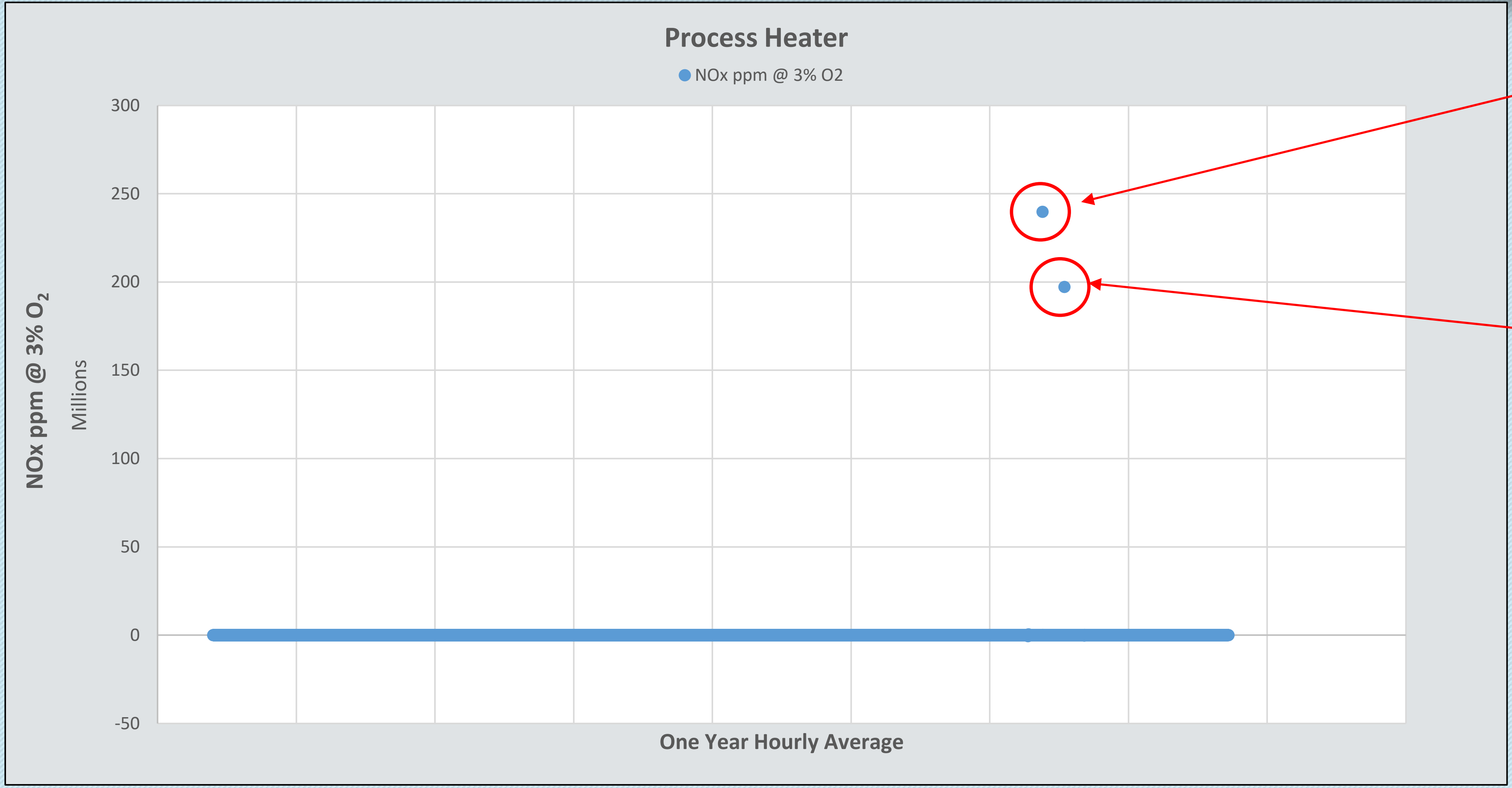
Measured O_2: *2 to 21%*

HHV: *993 to 2016 BTU/SCF*

Plotted NOx ppm @ 3% O_2



Example Analysis for 52 MMBtu/hr Heater (*con't.*)



Day 299

NOx: *239,842,232 ppm*

Measured O_2: *20.9 %*

Fuel flow rate: *0 MSCFH*

Heater capacity: *0%*

Conclusion: *outlier*

Day 302

NOx: *197,268,519 ppm*

Measured O_2: *20.9 %*

Fuel flow rate: *0 MSCFH*

Heater capacity: *0%*

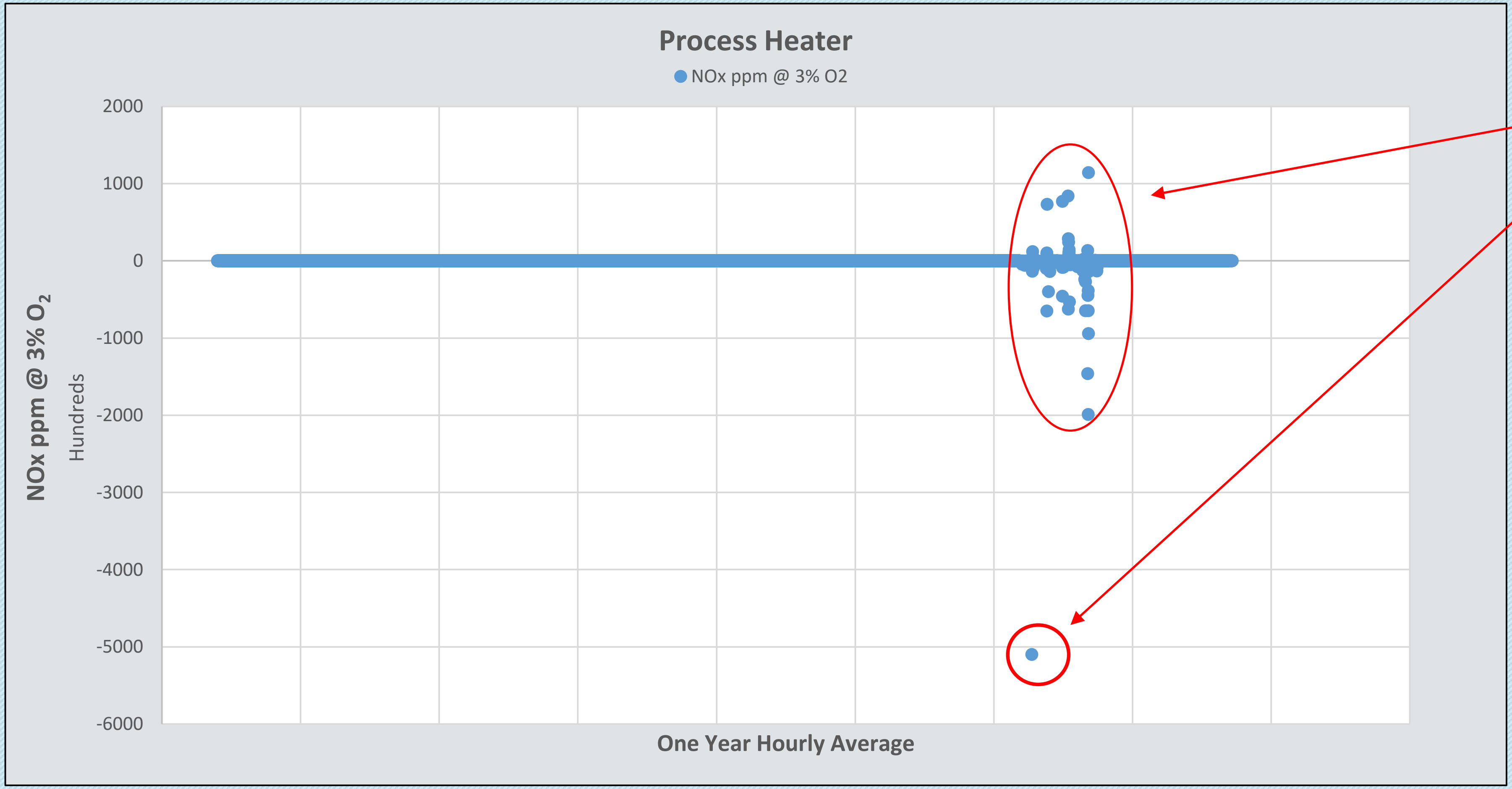
Conclusion: *outlier*

Conclusion

O_2 is ambient and no fuel flow, heater is down.

Excluded these data points.

Example Analysis for 52 MMBtu/hr Heater (*con't.*)



Day 286 to Day 323

NOx: *-510,016 to 114,208 ppm*

Measured O_2: *> 20 %*

Fuel flow rate: *0 to 5 MSCFH*

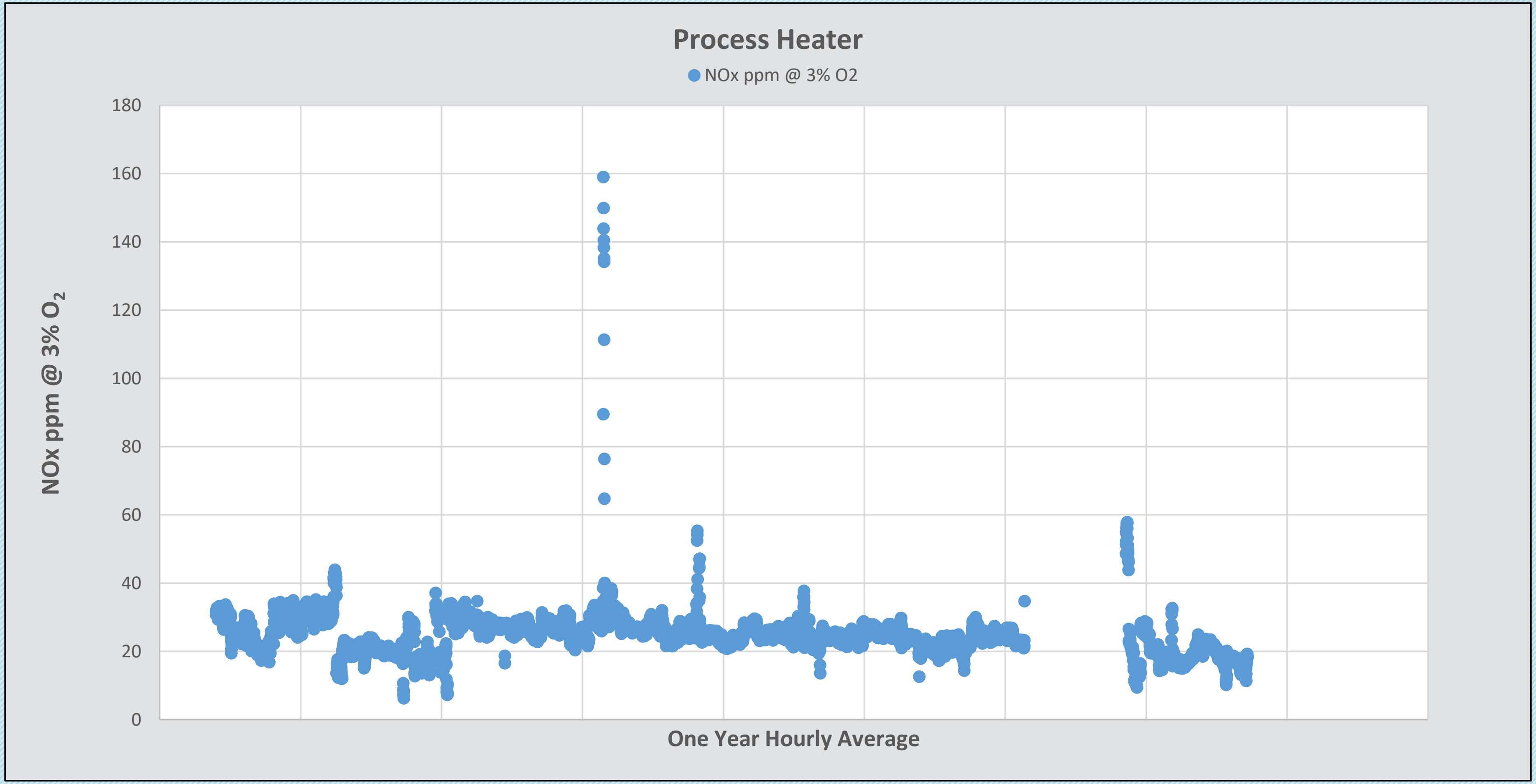
Heater capacity: *0 to 12%*

Conclusion: *outliers*

Conclusion

This data point has low fuel flow rate, ambient O_2, and <12% heater capacity. Perhaps start-up/shutdown condition. **Excluded data points.**

Example Analysis for 52 MMBtu/hr Heater (*con't.*)



Once all obvious outliers are eliminated, data is now more representative of normal operation parameters

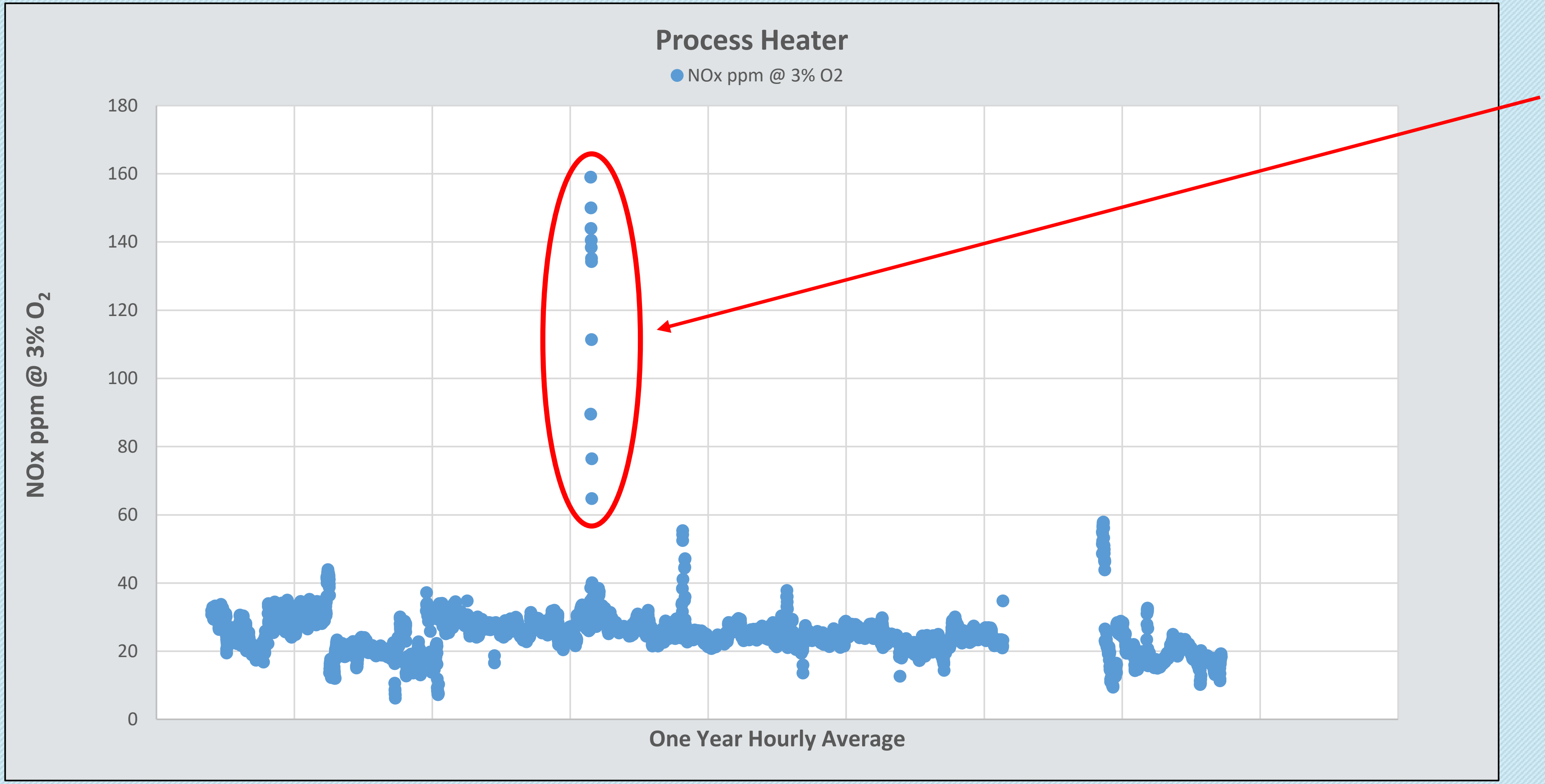
Estimating Normal Operational Parameters

- Staff evaluated 8,784 data points to determined 7,920 normal operational parameters after eliminating obvious outliers
- Averaged revised data set (with obvious outliers removed) and calculated standard deviation
- Normal Operational Parameters based on fuel flow, percent O_2, HHV, and heater capacity

Fuel Flow	**Average**	**23.6**
	Standard Dev	**8.3**
NOx	**Average**	**24.3**
	Standard Dev	**8.3**
% O_2	**Average**	**5.6**
	Standard Dev	**1.1**
HHV	**Average**	**1,388.6**
	Standard Dev	**84.9**

Normal Operational Parameters		
Parameter	**Range**	
Fuel Flow (MSCFH)	**15.3**	**31.9**
NOx (ppm)	**16.0**	**32.6**
% O_2	**4.5**	**6.7**
HHV (Btu/SCF)	**1,303.1**	**1,456.1**
Heater Capacity (%)	**38**	**91**

Example Analysis for 52 MMBtu/hr Heater (*con't.*)



Day 137

NOx @3%O_2: *65 to 159 ppm*

Fuel flow rate: ***3 to 16 MSCFH***

Measured O_2 : ***13 to 17%***

Heater capacity: ***8 to 36%***

Normal Operational Parameters

Fuel Flow Rate: *15 to 31 MSCFH*

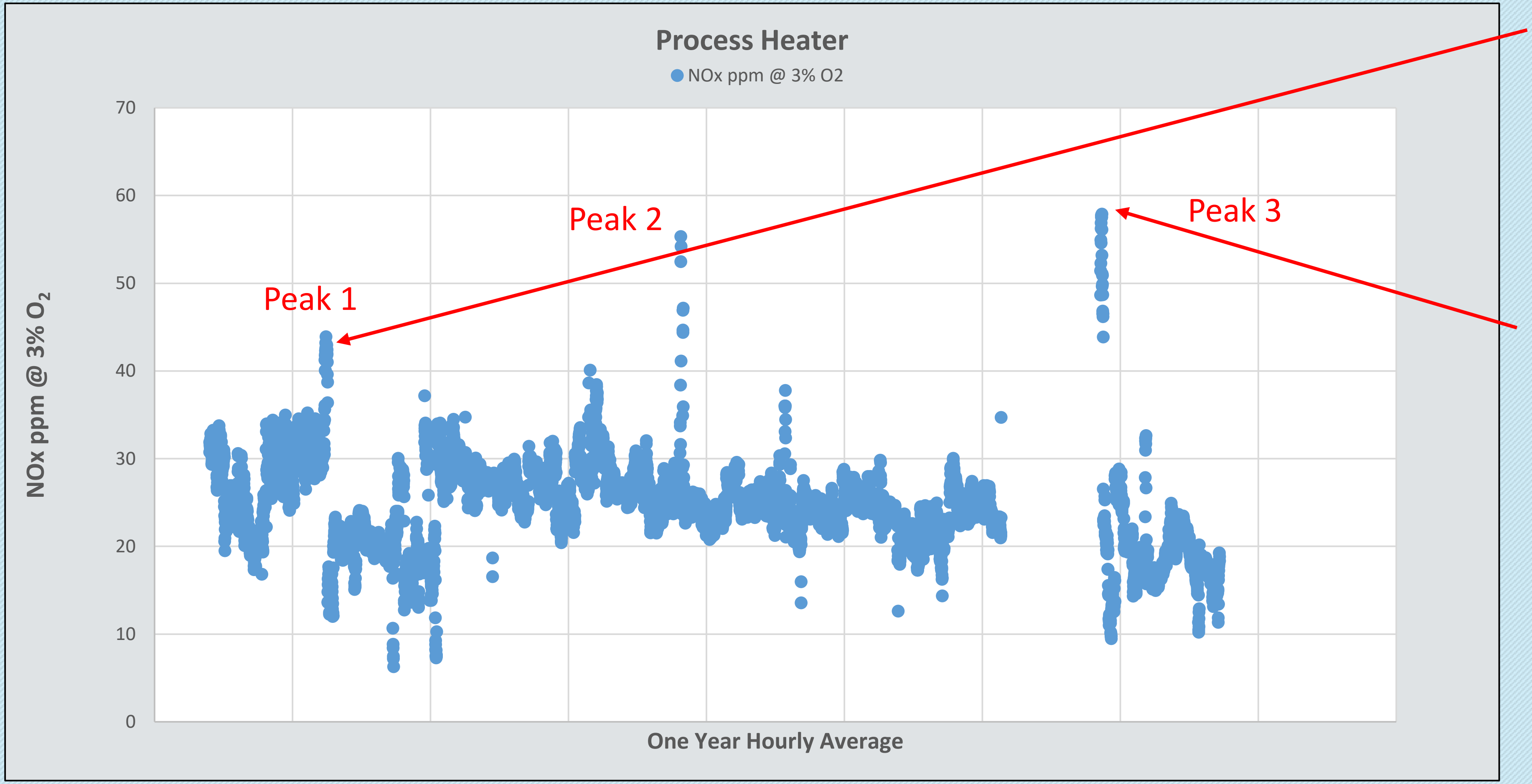
Measured O_2: *4.5 to 6.6%*

Heater Capacity: *38 to 91%*

Conclusion

Compared to "normal operation parameters", fuel flow rate is at reduced rate, high O_2, and heater capacity is less than normal range **Excluded NOx data.**

Example Analysis for 52 MMBtu/hr Heater (*con’t.*)

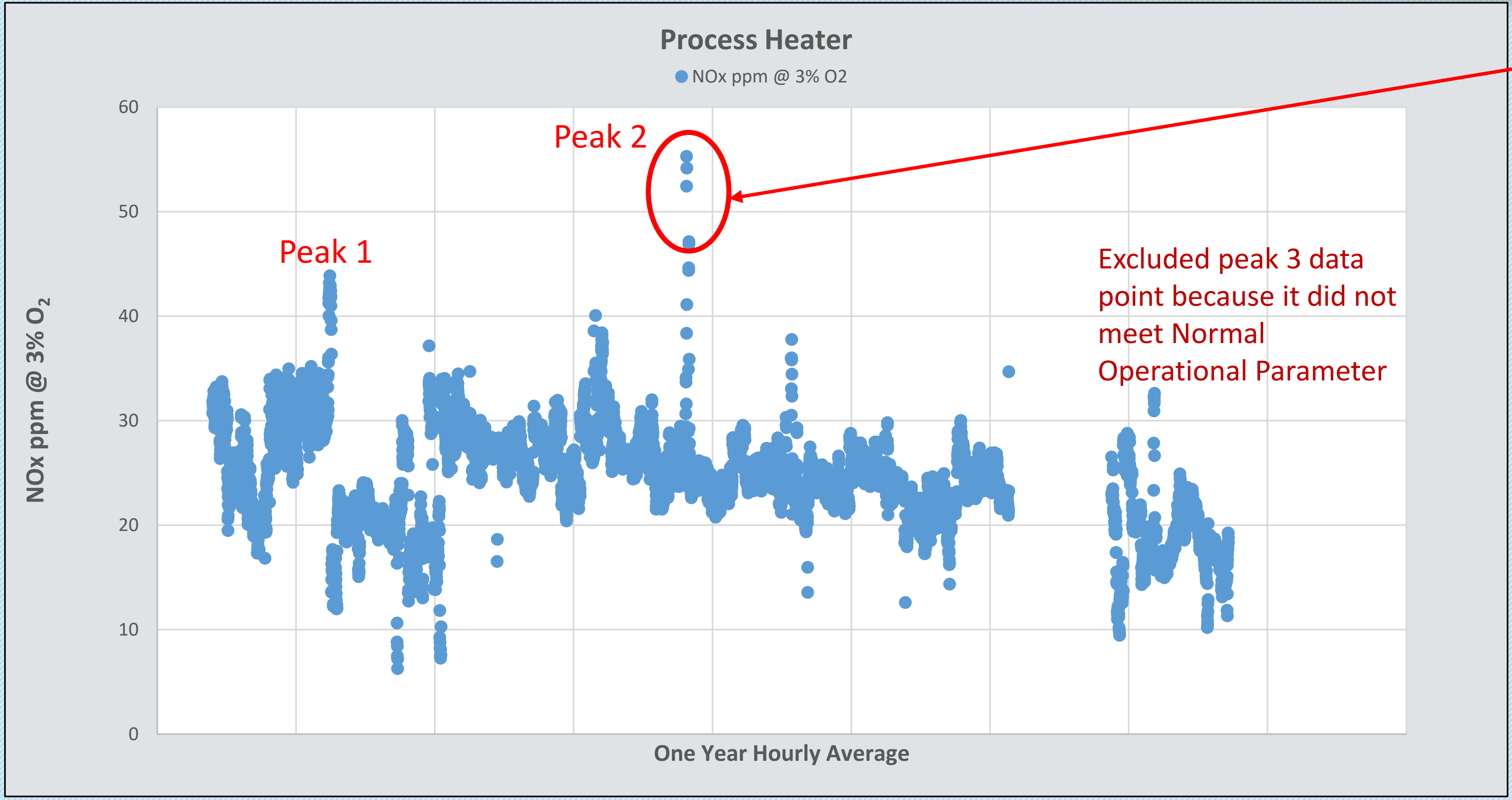


Peak 1 (Day 44)
NOx: *43.8 ppm*
Fuel Flow Rate: *20 to 21 MSCFH*
Measured O_2: *5 to 7%*
Heater Capacity: *50 to 52%*
Conclusion: *include*

Peak 3 (Day 323)
NOx: *57 ppm*
Fuel Flow Rate: ***5 to 10 MSCFH***
Measured O_2: ***17 to 19%***
Heater Capacity: ***8 to 10%***
Conclusion: *exclude*

Normal Operational Parameters
Fuel Flow Rate: *15 to 31 MSCFH*
Measured O_2: *4.5 to 6.6%*
Heater Capacity: *38 to 91%*

Example Analysis for 52 MMBtu/hr Heater (*con't.*)



Excluded peak 3 data point because it did not meet Normal Operational Parameter

Peak 2

NOx @3%O_2: *41 to 55.3 ppm*

Fuel flow rate: *31 MSCFH*

Measured O_2 : *4.4 to 4.6 %*

Heater capacity: *73 to 75%*

Conclusion: *include*

Normal Operational Parameters

Fuel Flow Rate: *15 to 31 MSCFH*

Measured O_2: *4.5 to 6.6%*

Heater Capacity: *38 to 91%*

Conclusion

56 ppm will be considered the operational peak

Example Analysis for 52 MMBtu/hr Heater (*con't.*)

	NOx (ppm @ 3% O_2)	Fuel Flow (Mscf/hr)	HHV (MMBtu/scf)
Survey Annual Average	23.3	201	1330
Operational Peak (CEMS Evaluation)	56	207	1289

CEMS Data Evaluation Conclusions

CEMS data shows operational variations in each unit

Can be used to identify outliers, define normal operation conditions, and estimate an operational peak

Operational peak defined as highest concentration, with outliers removed

Operational peak will be used for cost-effectiveness and emission reduction calculations

U.S. EPA SCR Cost Model

SCR Cost Model – Stakeholder Comments

- Stakeholders expressed concern that U.S. EPA SCR* cost model does not reflect the refining industry because it does not reflect:
  - Increased costs associated with California Senate Bill 54
  - Increased costs associated with space constraints or plot space limitations
    - Increase construction cost
    - Increased duct work
- U.S. EPA SCR cost model derived from cost to replace boilers at electricity generation facilities
  - Determines costs based on MW to MMBTU conversion
  - May underestimate SCR size and costs for refining industry

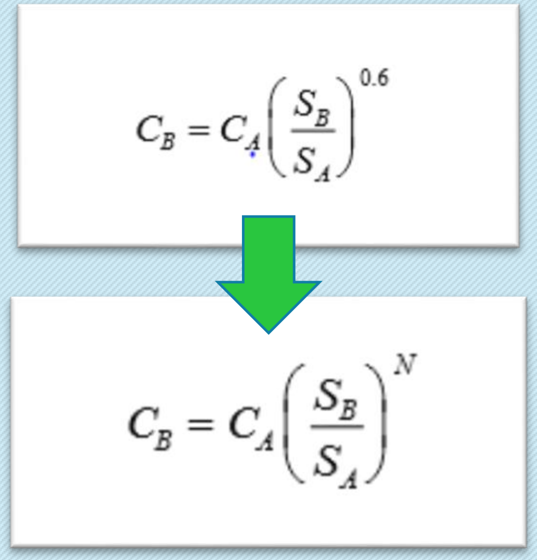
* Available at: http://epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

SCR Cost Model – Applications

- U.S. EPA SCR cost model is most comprehensive tool available to estimate the cost-effectiveness of an SCR installation
- Methodology based “The Rule of Sixth-tenths”
  - Approximate costs can be obtained based on unit with different size or capacity
  - Uses cost indices to adjust to current total capital investment price
- Model is used and applied to many other industries
- Widely used for regulatory purposes
- Model tends to overestimate SCR installation costs for most industries
- Unique challenges at refineries increases costs

SCR Cost Model – Rule of Six-tenths

- U.S. EPA SCR cost model is based on the “Rule of six-tenths” or “six-tenths-factor” rule of thumb
- Scaling factor rule uses ratio and proportioning to estimate costs
    - If cost of a given unit at one capacity/size is known, the cost of a similar unit with “X” times the first is approximately $(X)^{0.6}$ times the cost of the initial unit



$$C_B = C_A\left(\frac{S_B}{S_A}\right)^{0.6}$$

$$C_B = C_A\left(\frac{S_B}{S_A}\right)^{N}$$

C_B = approximate cost of equipment having size S_B (MMBtu/hr, hp, scfm, etc.)

C_A = known cost($) of equipment having corresponding size S_A (same units as S_B)

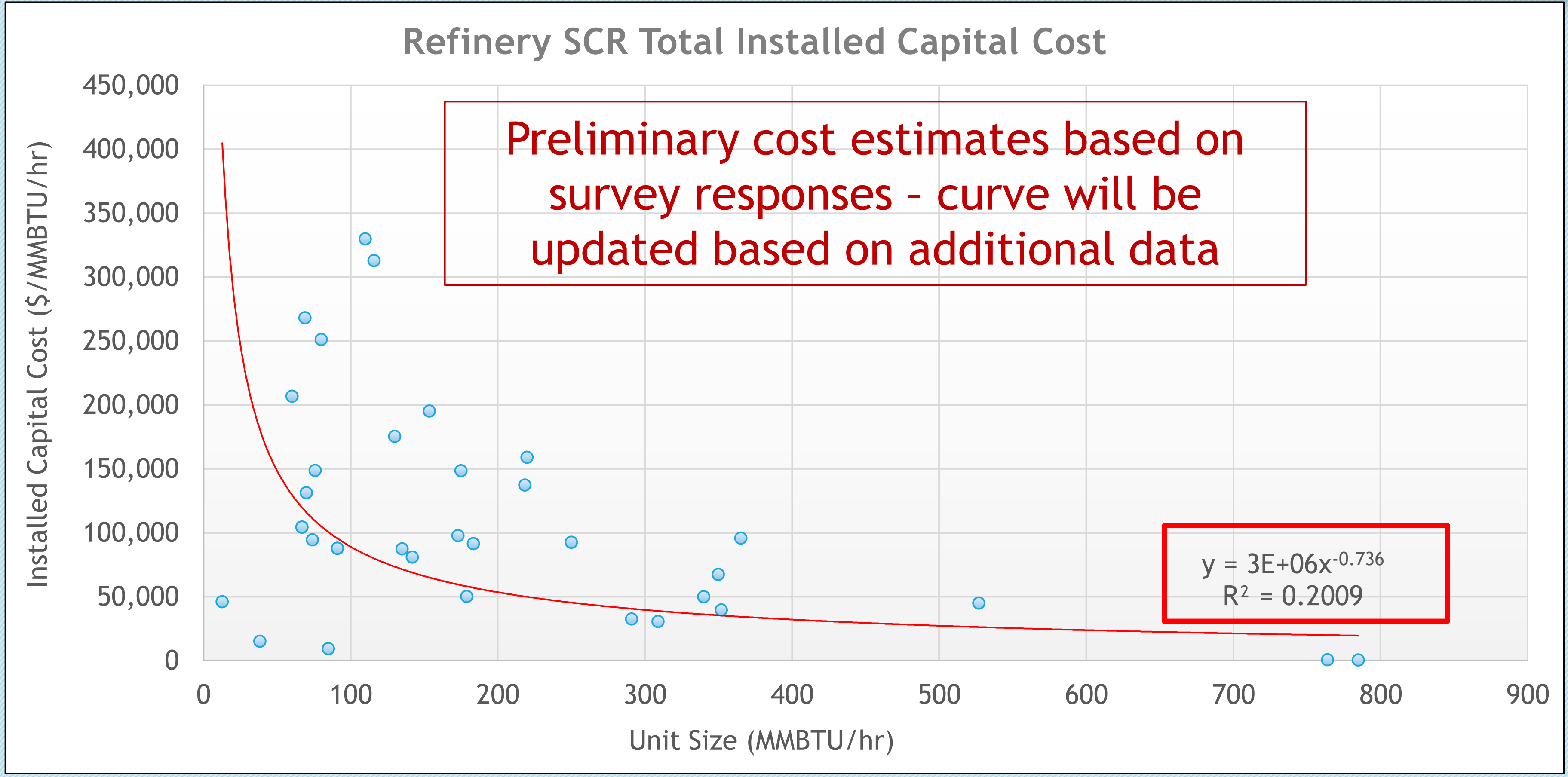
S_B/S_A = ratio size factor

N = size exponent (varies 0.3 to >1.0, but average is 0.6)

SCR Model –Installation Costs

- Staff acknowledges costs at refineries could be higher
- SCR installation costs provided by nine stakeholders in 2018 survey for 35 heaters
  - Preliminary costs varied from $500K to $36.5 MM
  - Unknown if cost estimates are order of magnitude or detailed engineering estimates
  - No itemized details on costs (e.g., engineering, material, labor, and dollar year)
- Staff requesting detailed cost estimate information for SCR installations
  - Capital cost
  - Installation costs
  - Dollar year of cost
- Actual cost estimates provided from stakeholders will be used to generate a new cost curve more representative of refining industry in California

SCR Model - Cost Curve from Survey



Preliminary cost estimates based on survey responses – curve will be updated based on additional data

- Updated cost information will be used to generate a cost curve based on actual costs
- Equation generated from data will be used in SCR model modification
- Solving equation will give us costs in $/MMBTU/hr

Other Cost-Effectiveness Metrics

Gas Turbines

- SCR cost model will be used as is to determine cost effectiveness
- Installation cost can be scaled up to reflect SB54
- Used and applied in Rule 1134 and 1135

FCCU and Coke Calciner

- SCR cost model not applicable to FCCU, NOx is determined by feed rate
- Cost will be based off actual installation costs and/or vendor quotes
- Discounted Cash Flow (DCF) method will be used calculate cost-effectiveness

SRU/Tailgas Incinerators/ Thermal Oxidizers

- No control technologies identified at this time
- DCF method for cost-effectiveness calculation

Internal Combustion Engines

- Only used during start-up
- Likely fall under low-use exemption
- BACT limit apply to new installations

Next Steps

- Update U.S. EPA Cost Model
- Continue BARCT Assessment and Cost Effectiveness
- Continue Facility Site Visits
- Propose BARCT Limits
- Final Assessment Report from Consultants
- Finalize BARCT Limits

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