Attachment 1:

Gas Transmission Northwest
Compressor Station No. 12 – Four Factor Analysis

This attachment includes the four factor analysis for Compressor Station Number 12.

Four-Factor Analysis for GTN Compressor Station No. 12

Gas Transmission Northwest (GTN) Compressor Station No. 12 is located near Bend, Oregon and operates under Oregon DEQ permit number 09-0084-TV-01. In a December 23, 2019 letter, DEQ requested a "four factor" analysis associated with its regional haze second planning period (Round 2) State Implementation Plan (SIP). This document provides the four factor analysis conducted for the facility. The analysis considers application of NOx control on the facility combustion turbines, following EPA's draft guidance document[1], standard methodologies from the EPA Control Cost Manual that are recommended in section 7 of the EPA guidance document, and recommendation (e.g., 20 year amortization for control costs) from DEQ support material.

When assessing NOx control cost effectiveness, DEQ has requested that uncontrolled NOx emissions be based on "PSEL". The associated emissions (tons per year) accounts for actual emissions based on source test results, but assumes maximum operating time, i.e., 8,760 hours annually. In contrast, EPA's Regional Haze Guidance document recommends using operations projected for 2028. Interstate natural gas transmission lines are regulated by the Federal Energy Regulatory Commission (FERC), and are designed to meet peak short-term natural gas demand, which rarely occurs. Thus, typical operation for many units is much lower than the annual hours associated with DEQ's PSEL annual emissions. That utilization is documented for past operation at Station 12, and annual operations commensurate with PSEL annual limits is not anticipated in future years. Thus, this analysis presents economic analysis for NOx control (i.e., cost per ton of NOx removed) assuming three scenarios for annual operation for each unit: PSEL-based operation, past operations, and projected future operation. As discussed below, warranties for emissions controls are much less than 20 years, so costs associated with 10 year amortization are also presented.

Station 12 includes three simple cycle natural gas-fired combustion turbines that drive natural gas compressors: a General Electric LM 1600 (Unit 12A) rated at 19,200 horsepower (hp); a Cooper Rolls Avon (Unit 12B) rated 14,300 hp; and a Solar Titan (Unit 12C) rated at 19,200 hp. Units 12A and 12B have "diffusion flame" burner technology, consistent with the state of the art when the units were built and installed. The Solar Titan was added to the facility at a later date (2001) and the PSD determination required lean premixed combustion burner technology, which lowers NOx emissions. Station 12 also includes a small emergency generator. The four factor analysis does not review emission controls for the emergency generator because of its very limited run time.

[1] Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA document number EPA-457/P-16-001 (July 2016).

Unit 12C has a lower NOx limit than the other two turbines and includes “lean premixed combustion” technology in conjunction with the PSD analysis conducted when the turbine was added to the facility in 2001. As documented in the 2006 EPA NSPS for combustion turbines (40 CFR, Part 60, Subpart KKKK), the state of the art NOx emissions control for new turbines is “lean premixed combustion” technology, which offers lower NOx emissions than diffusion flame burners. However, for units 12A and 12B, the manufacturers do not offer a burner retrofit option for lean premixed combustion, and after-market options for lean premixed combustion are not available. Thus, the four factor analysis considers other “add-on” control options. Despite the lack of retrofit burner technology, turbines with diffusion flame burners are still relatively low emitting combustion sources (i.e., emissions are relatively low in comparison to other combustion devices such as reciprocating engines or units that burn other types of fuel).

Regarding SO_2 emissions, the emissions inventory calculation is based on fuel sulfur content of 1 grain per 100 SCF. However, actual sulfur content is much lower. Fuel analysis is conducted regularly, and measured values are nearly an order of magnitude lower. The average value from two years of daily gas analyses (2018 and 2019) is 0.15 grains per 100 SCF. The annual facility SO_2 emissions in the emission inventory are less than 5 tons per year (TPY) assuming the higher value, so actual emissions based on gas analysis results indicate emissions are significantly lower than 1TPY. Because SO_2 emissions are very low from units firing pipeline quality natural gas, no additional discussion of SO_2 emissions is included in this analysis. Similarly, fine particulate (PM_{10} or $PM_{2.5}$) emissions are very low for natural gas-fired turbines and no additional analysis is conducted.

Factor #1 – NOx Emissions Controls and Control Cost

The pollutant of concern for a natural gas-fired turbine is nitrogen oxides (NOx). As noted above, the GE LM 1600 turbines (12A) and Cooper Rolls Avon turbine (12B) do not have a low NOx combustor (i.e., lean premixed combustion) retrofit option. EPA guidance document indicates that both retrofit and replacement should be considered. However, replacement costs for these units would be exorbitant.

Replacement

Replacement for the Solar Titan (12C) is not appropriate because little or no emission benefits would be achieved by replacing a unit that already employs state of the art lean premixed combustion. For the other two units, an approximate, “rule of thumb” cost of replacing existing compressor drivers is $3,000 per horsepower or more. Recent corporate review for turbines similar to Unit 12B indicated replacement costs exceeding $50 million and costs ranging from $3,500 to $5,000 per horsepower. In comparison, retrofit costs for selective catalytic reduction (SCR) discussed below are less than $400 per hp (see Table 1 or Table 2, “Total Capital Investment” costs). Thus, capital investment for replacement is more than an order of magnitude higher than the analysis presented below to achieve a similar reduction in NOx emissions. Cost effectiveness values for NOx would exceed $50,000 per ton to replace Unit 12A and exceed $100,000 per ton to replace Unit 12B. Notably, SCR technological concerns (discussed below) could force a choice between a technology that could impact reliability (and unit availability to meet natural gas demand) and exorbitant costs. Replacement is not discussed further in this analysis.

Add-on retrofit controls

Since combustion control is also not an option for units 12A and 12B, the remaining add-on control technologies applicable are selective catalytic reduction (SCR) or water/steam injection. As discussed below, the latter is not technologically feasible for the diffusion flame units. Lean premixed combustion technology (which is sometimes referred to as "dry low emissions" or DLE combustion) replaced water/steam injection as the state of the art burner technology over two decades ago and water/steam injection is not applicable to unit 12C.

Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NOx control cost effectiveness for SCR for all three units. A cost effectiveness analysis was not conducted for water injection for units 12A and 12B due to its very limited application to industrial turbines, and the associated difficulty in estimating capital and other costs. Additional discussion on water injection technical feasibility is provided below; capital costs would be higher and NOx reductions would be lower than the SCR scenario evaluated, so cost effectiveness values would be higher than the costs associated with SCR.

Other post-combustion NOx control options discussed in the literature are not applicable for combustion turbines. For example, "non-selective catalytic reduction" (NSCR) is a technology to reduce NOx emissions, but that technology only applies to reciprocating engines where the air-to-fuel ratio (AFR) is controlled so that there is no excess combustion air (i.e., exhaust O_2 levels are close to zero). At these conditions, species such as ammonia naturally occur in the combustion exhaust and those species participate in catalytic reactions to reduce NOx. This combustion configuration and AFR is not applicable to combustion turbines. Another technology, "selective non-catalytic reduction" (SNCR) employs similar "ammonia + NOx" chemistry, with ammonia injected at higher temperatures to reduce NOx without the use of a catalyst. In contrast, similar chemistry occurs with SCR technology but a catalyst is required for reactions to occur because the exhaust temperature is cooler. SNCR has been applied in limited cases to large boilers (e.g., utility scale electric generating units), where the boiler configuration provides ample residence time at a temperature of about 1700 °F. A very specific temperature range and residence time within that range is required for SNCR to function. Neither the temperature or residence time is available in a combustion turbine, thus SNCR is not applicable to turbines. SCR is the only potential technology, and cost analyses follow for SCR control. That discussion is preceded by a review of water/steam injection feasibility for units 12A and 12B.

Water injection technical feasibility for GE LM1600 (12A) and Cooper Rolls Avon (12B)

Water/steam injection control is a technology that was applied to turbines over two decades ago, but has had very limited use in recent years, as either combustion controls or SCR have been employed. A key concern with water injection is significant increases in emissions of products of incomplete combustion such as carbon monoxide (CO). NOx emissions would be higher than for the SCR analysis discussed above. For example, a NOx reduction of 75% may be possible at full load with water injection, but at the reduced load operation, lower uncontrolled NOx emissions and less reduction would be anticipated. When water injection was employed in limited cases, a five to eight fold increase in CO was likely; similarly, CO emissions would increase further when operating at less than full load. This may necessitate installation of an oxidation catalyst, with a cost similar to the NOx technology costs.

Turbine performance would also likely be negatively impacted due to operational challenges, because this technology has not been demonstrated for natural gas transmission facilities. Water/steam injection technology was supplanted by low emissions combustion over 20 years ago, and combustion-based emission control options are not available for the two units at station 12 with diffusion flame combustion. GTN believes that environmental and technological issues support a conclusion that water/steam injection is not technologically feasible. A cost effectiveness analysis is not presented, but would likely show a higher cost per ton than the SCR analysis presented below. Costs would be incurred beyond the base costs for NOx control and performance issues would arise, including: (1) addressing emissions of CO and other products of incomplete combustion, (2) contingencies associated with implementing a technology with very limited historical application and no installations at compressor stations in recent years, and (3) deleterious operational effects from lower unit efficiencies (e.g., more fuel use) and potential combustion instability when implementing the technology, especially when operating at other than full load.

SCR control analysis

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers. A case study for a retrofit application in California and related SCR review[2,3] showed significant problems, system re-engineering, and ultimately revisions to permit limits, including higher emission limits for ammonia slip. A more recent installation on a compressor driver also presented technological challenges and added costs associated with: exhaust temperature requirements and supplemental systems required to manage temperature over the operating range of the unit; reagent feed rate control system upgrades required to meet NOx requirements; commissioning challenges that increases anticipated schedule and costs by more than a factor of two; and managing safety issues associated with ammonia handling triggering OSHA Process Safety Management (PSM) requirements for the facility. As noted above, these raise serious questions regarding SCR performance, reliability, and technological feasibility. Thus, an operator would need to consider these operational risks versus the high costs associated with replacement if NOx mitigation is required. Additional review of technological challenges for SCR application to compressor drivers is currently being conducted by the Pipeline Research Council International (PRCI), a collaborative research group. Findings that supplement the information above may be provided at a later date if available on a timely basis.

Rather than providing additional details on technological feasibility, SCR cost analyses are presented to assess economic feasibility for the three turbines at Station 12. The analysis primarily relies on Control Cost Manual methods and related EPA support documentation. A key input for the analysis is the capital cost, and a 2016 Control Cost Manual (CCM) supplement that updated the SCR chapter[4] of the CCM was used to estimate the capital cost. Capital cost is based on information provided in Table 2.1b of the document.

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[2] L. Sasadeusz, G. Arney, et.al., "Establishing "Achieved in Practice" Emission Limits For a Simple Cycled Gas Compressor Operating Under Variable Speed", Gas Machinery Conference, Nashville, TN, October 2002.
[3] G. Arney, D.B. Olsen, and R. Mayces, "Challenges in Retrofitting Selective Catalytic Reduction (SCR) Systems to Existing Stationary Natural Gas Fired Engines", GMRC Gas Machinery Conference, Nashville, TN, Oct 2-5, 2011.
[4] "Chapter 2, Selective Catalytic Reduction," EPA update to Control Cost Manual, Table 2.1b (May 2016). Cost based on cost estimate presented in Table 2.1b for 12 MW unit.

Details of the cost effectiveness analysis are presented in tabular form in three tables provided at the end of this document. As discussed below, costs effectiveness values are presented for each unit assuming three different utilization rates, and the three tables show the case assuming full utilization (i.e., 8,760 hours per year). Table 1 presents the analysis for unit 12A. Table 2 presents the analysis for unit 12B. Table 3 presents the analysis for unit 12C. For the first two units, 75% reduction of NOx is assumed. Since the Solar Titan includes low NOx combustion technology, NOx emissions at the inlet to the SCR catalyst are significantly lower and the reduction across the catalyst will also be lower; 60% reduction is assumed for unit 12C.

Tables 1 through 3 present the cost details and unit-specific itemized cost elements following EPA Control Cost Manual methodology. The primary assumptions and inputs for each of the three units are detailed below. As discussed below, cost effectiveness results are presented for three different operating scenario assumptions. The three tables present the analysis details associated with the PSEL-based assumption which is based on full capacity operations (8,760 hours per year). In addition, the following assumptions or analysis are used for all three units:

- Capital cost recovery is based on a twenty year life and interest rate of 5%. Longer life is not appropriate for catalytic systems which typically have *a warranty of no longer than five years*. It would be reasonable to assume a shorter life for capital recovery. The twenty year life is conservatively high and consistent with recommendation in DEQ's Four Factor Analysis Fact Sheet. The interest rate assumed is a reasonable assumption, and a higher interest rate (e.g., 7%) is often used in control cost analysis to reflect the time value of money over a 20 year period. DEQ's Fact Sheet recommends using the current bank prime rate, but the current value (3.25%) is suppressed due to the very unusual current economic situation and that value is not appropriate for a longer term assessment. The interest rate affects the capital recovery factor (CRF) in the analysis, but assuming the lower rate does not significantly impact the cost per ton value (i.e., less than 10%). While details are not presented below, capital cost recovery based on 10 years rather than 20 years may be a more appropriate assumption based on system warranties and the lack of a proven record for SCR application to compressor drivers. A ten year timeframe increases the cost effectiveness values below by approximately 30%.
- Utilization / annual operating hours: Cost effectiveness values are presented below for three different scenarios, and the assumed utilization affects annual NOx emissions and thus the cost effectiveness value. NOx emissions based on the PSEL consider the emission rate based on source test data but assume full capacity operation (i.e., 8,760 hours per year). As noted above, compressor stations on interstate pipelines are regulated by FERC and site capacity is designed to meet peak natural gas demand, which rarely occurs. Thus, utilization at compressor stations is typically well less than full capacity. As reflected in the DEQ letter requesting this analysis (i.e., by comparing 2017 emissions to potential emissions), run time at the facility has typically been much lower for the two units with higher baseline NOx emissions. The Solar Titan unit that includes a low NOx combustor is preferentially operated and has much higher utilization. DEQ has requested cost effectiveness analysis based on PSEL (i.e., 100% utilization), but sensitivity to assumed operating hours is presented in this analysis. The following utilization scenarios are included:
  - Assume 100% utilization. This is the value assumed for the detailed cost effectiveness computation presented in Tables 1 through 3. This value is not consistent with past operations, future projections, or recommendations in EPA's regional haze guidance.

- Assume utilization based on recent operations. Table 4 presents the last three years of utilization and fuel use for the three units at station 12. The average utilization from the last three years is used in the analysis. The average utilization for Unit 12A was 20.2% (1,767 hours), the average for Unit 12B was 21.6% (1,892 hours), and the average for Unit 12C was 80.1% (7,013 hours).
- Assume future projected utilization. EPA guidance recommends projecting utilization in 2028. GTN projections assume pipeline system conditions may result in marginally higher future operations at Station 12. Projected utilization is 42.5% (3,723 hours) for Units 12A and 12B, and 85% (7,446 hours) for Unit 12C.

- Most other costs (direct and indirect installation costs, etc.) are based on the Control Cost Manual.

- Reagent cost is based on a cost estimate of $700 per ton for ammonia and a molar ratio (NOx / NH_3) of 1.1. The ammonia cost is based on information available on-line from the U.S. Department of Agriculture[5] for the cost of ammonia, which varies depending on market conditions. In recent years, cost has ranged from about $500 to over $800 per ton. A cost of $700 per ton is assumed in the analysis. The cost effectiveness value is relatively insensitive to nominal changes in this cost.

GE LM 1600 (unit 12A) SCR cost analysis assumptions:

- As shown in Table 1, a capital cost of $3,712,500 to achieve 75% reduction in NOx, based on Chapter 2 of the Control Cost Manual. The Control Cost Manual Table 2.1b information for SCR cost is $167 per kilowatt (in 1999$) for a 12 MW, $237/kw for a 2 MW unit and $51/kw for an 80 MW unit. The unit rating of 19,200 hp is approximately 14.3 MW, so the 12 MW example provided by EPA is reasonable for the LM 1600 turbine at station 13. The LM series turbines are "aero-derivative" units rather than a design founded in industrial applications, which could add some costs for retrofit SCR. That factor is not considered in this analysis. The cost is adjusted from 1999 to 2020 using the consumer price index (CPI), and the CPI adjustment factor is 1.553.

- As reflected in the DEQ letter (i.e., by comparing 2017 emissions to potential emissions), run time at the facility has typically been less than 20% of maximum annual operating hours, and utilization has been lower for the two units with diffusion flame combustion versus unit 12C. As discussed above, cost effectiveness values are presented for three utilization scenarios: 100% use (PSEL basis), average utilization in the last three years, and projected future utilization.

- NOx emission rate: Based on test results and estimate of unit fuel use, an uncontrolled NOx emission factor of 0.366 lb/MMBtu is assumed. The factor in engineering units of lb/MMBtu is based on the PSEL emission factor of 373.0 lb/MMscf natural gas, and unit heat rate of 7,500 Btu/hp-hr (high heating value basis). The heat rate is consistent with facility information, and the heat rate for a mechanical drive LM 1600 published in a turbine specification available in the literature and also included in the turbine NSPS docket.[6]

[5] Anydrous ammonia price fluctuates; $700 per ton is within range in recent years. For example, see U.S. DOA worksheet Table 7 and Table 8 at: https://www.ers.usda.gov/data-products/fertilizer-use-and-price/ and figures at: https://www.michfb.com/MI/Farm_News/Content/Crops/Adjusting_nitrogen_plans_based_on_fertilizer_prices_trends/

[6] Gas Turbine World Performance Specs, Performance Rating of Gas Turbine Power Plants for Project Planning, Engineering, Design, Procurement. See EPA Docket Document Number EPA-HQ-OAR-2004-0490-0105.

  - Based on information in the previous bullets, the NOx emission rate prior to SCR control is 52.7 lb/hr.

The resulting estimate of NOx control cost effectiveness for Unit 12A is:

- **$6,719 per ton** assuming 100% (i.e., PSEL-based) utilization;
- **$32,071 per ton** assuming average utilization (20.2%) from 2017 – 2019;
- **$15,386 per ton** assuming future projected utilization (42.5%).

GTN believes that the cost effectiveness values with utilization assumptions more representative of actual or forecast unit operation exceed a reasonable threshold. The PSEL-based value may be approaching a range that appears reasonable, but when considering actual operations, questions regarding SCR technological feasibility, and other factors discussed below, emissions mitigation is not warranted for this unit. In addition, the discussion above on SCR technological feasibility identifies a case study where SCR costs were more than double anticipated costs due to commissioning and operational issues. The Control Cost Manual methodology used for this analysis does not account for such significant contingencies. Based on lessons learned from that case study, technological challenges could double the cost effectiveness values presented.

Cooper Rolls Avon (unit 12B) SCR cost analysis and assumptions:

- As shown in Table 2, a capital cost of $2,765,000 to achieve 75% reduction in NOx, based on Chapter 2 of the Control Cost Manual. The Control Cost Manual Table 2.1b information for SCR cost is $167 per kilowatt (in 1999$) for a 12 MW unit. The unit rating of 14,300 hp is approximately 10.66 MW, so the 12 MW example provided by EPA is reasonable for the Avon turbine. The cost is adjusted from 1999 to 2020 using the consumer price index (CPI), and the CPI adjustment factor is 1.553.

- As discussed above, cost effectiveness values are presented for three utilization scenarios: 100% use (PSEL basis), average utilization in the last three years, and projected future utilization.

- Based on test results and a conservative estimate of unit fuel use, an uncontrolled NOx emission factor of 0.170 lb/MMBtu is used. The factor in engineering units of lb/MMBtu shown in Table 2 is based on the PSEL emission factor of 173.9 lb/MMscf natural gas, and a unit heat rate of 9,500 Btu/hp-hr (high heating value basis), which is typical for this model and consistent with published values from the EPA docket document discussed above for unit 12A.
  - From the previous bullets, the NOx emission rate prior to SCR control is 23.1 lb/hr.

The resulting estimate of NOx control cost effectiveness for Unit 12B is:

- **$11,449 per ton** assuming 100% (i.e., PSEL-based) utilization;
- **$51,869 per ton** assuming average utilization (21.6%) from 2017 – 2019;
- **$26,514 per ton** assuming future projected utilization (42.5%).

GTN believes these values exceed a reasonable cost threshold, and the cost effectiveness values resulting from utilization assumptions more representative of actual or forecast unit operation significantly exceed a reasonable threshold.

Solar Titan (unit 12C) SCR cost analysis and assumptions:

- As shown in Table 3, a capital cost of \$3,770,500 to achieve 60% reduction in NOx, based on Chapter 2 of the Control Cost Manual. The Control Cost Manual Table 2.1b information for SCR cost is \$167 per kilowatt (in 1999\$) for a 12 MW unit. The unit rating of 19,500 hp is approximately 14.5 MW, so the 12 MW example provided by EPA is reasonable for this turbine. The cost is adjusted from 1999 to 2020 using the consumer price index (CPI), and the CPI adjustment factor is 1.553. As noted above, a lower control efficiency is assumed because the SCR inlet NOx emissions are lower (i.e., less than 20 ppmv).
- As discussed above, cost effectiveness values are presented for three utilization scenarios: 100% use (PSEL basis), average utilization in the last three years, and projected future utilization.
- Based on test results and an estimate of unit fuel use, the pre-SCR NOx emission factor for this unit with low NOx combustion is 0.052 lb/MMBtu. The factor in engineering units of lb/MMBtu shown in Table 3 is based on the PSEL emission factor of 52.6 lb/MMscf natural gas, and unit heat rate of 6,750 Btu/hp-hr (high heating value basis) based on test results and published values from the EPA docket document discussed above for unit 12A.
  - From the previous bullets, the NOx emission rate prior to SCR control is 6.8 lb/hr.

The resulting estimate of NOx control cost effectiveness for Unit 12C is:

- **\$62,996 per ton** assuming 100% (i.e., PSEL-based) utilization;
- **\$78,591 per ton** assuming average utilization (80.1%) from 2017 – 2019;
- **\$73,846 per ton** assuming future projected utilization (85%).

These values significantly exceed a reasonable cost threshold.

Factor #2 – Time Necessary for Compliance

Retrofitting SCR would require a timeline of three years or more. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. A schedule up to five years could be required because previous retrofit installations of SCR on natural gas transmission compressor drivers are very limited, and have resulted in extended commissioning periods to address performance issues with the reagent control system (e.g., ability of the reagent flow control to adequately respond to emissions changes as pipeline demand changes turbine load and NOx emissions). The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity.

Factor #3 – Energy and Other Environmental Impacts

SCR for NOx results in a fuel penalty and requires use of electricity to drive reagent pumps. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. SCR would also introduce other air impacts – e.g., ammonia emissions. Ammonia can form ammonium nitrate in the atmosphere and is a particulate precursor). Thus, depending on the local atmospheric chemistry, an increase in ammonia emissions could actually exacerbate particulate matter formation. There are additional environmental impacts associated with ongoing ammonia transportation to the facility, and catalyst production and disposal.

In addition, DEQ background documentation[7] on its regional haze program shows that the facility does not rank high on the list of facilities required to conduct a four-factor analysis based on the "Q/d" (emissions / distance) value. The DEQ list of facilities requiring a four factor analysis is based on those with Q/d over 5 using PSEL emissions Based on actual operations, the Q/d for Station 12 is 2.3, which ranks low on the list of facilities. The discussion above on utilization indicates that even if emissions increase to a level commensurate with a possible future increase in utilization, the Q/d ratio will still be approximately 5 or lower. This implies that the facility is less likely to have an impact on visibility than most others on the list.

Factor #4 – Remaining Useful Life of the Source

As noted in the EPA guidance document, control technology life will likely be shorter than the expected life of the stationary source. That is the case for a combustion turbine. The cost analysis assumes control technology life of twenty years for SCR. A twenty year lifetime exceeds typical estimates for emission control analysis presented in a U.S. Department of Energy (DOE) report[8], control technology analysis in EPA regulations and regulations from other states, and greatly exceeds the technology warranty. The turbine life is longer and not limited if standard maintenance requirements are followed.

Summary

In summary, the four factor analysis results for SCR NOx cost effectiveness exceed $11,000 per ton for all cases other than the PSEL-based utilization scenario for unit 12A. Unit 12C already includes low NOx combustion and further reductions are not feasible. For Unit 12B, the NOx cost effectiveness exceeds $25,000 per ton based on recent operations and future utilization projections. Assuming 100% utilization, which will not occur due to characteristic operations for natural gas transmission compressor stations, cost effectiveness is over $11,000 per ton. GTN recommends nothing additional for Unit 12B.

For Unit 12A, SCR cost effectiveness is $6,719 per ton. However, when considering recent operations or possible future operating scenarios, the value increases to $15,000 to $32,000 per ton. In addition, an SCR case study discussed above indicates SCR costs (and thus cost effectiveness values) could double due to technological challenges. DECs threshold for considering additional mitigation is not clear, but $6,700 per ton may exceed that threshold. If not, when considered with factors such as SCR technological feasibility, Q/d for the facility, other energy and environmental factors (e.g., increased emissions of the particulate precursor ammonia), and EPA's recommendation to consider 2028 projected emissions rather than 100% utilization, it is clear that no additional control requirements are warranted for Unit 12A. GTN recommends no further control requirements for the three turbines at compressor station 12.

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[7] DEQ Regional Haze Program, "List of Facilities that qualified for four factor analysis based on PSEL Q/d (2017) > 5 (January 2020). https://www.oregon.gov/deq/FilterDocs/haze-QDFacilitiesList.pdf

[8] "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines," Department of Energy, Prepared by ONSITE SYCOM Energy Corporation under Contract No. DE-FC02-97CHIO877 (November 1999).

Table 1. General Electric LM 1600 Turbine (Unit 12A) SCR NOx Control Cost Effectiveness (100% utilization case).

NOx Control Cost Effectiveness Estimate					
Engine Manufacturer	General Electric				
Model No.	LM 1600				
Unit ID	12A				
Fuel Used	Natural Gas				**Color Legend**
Emissions Control	SCR				User Data / Information Input Cell
Combustion Control Purpose	NOx				"Cumulative" Cost Cell for Primary Categories
Target Reduction	75%				Cost Effectiveness ($ / ton)
1 Engine Design Conditions					**Comments**
Power Output	19200	(hp)			Rated HP
Engine Exhaust Temperature		(F)			*optional input*
Engine Exhaust Rate		(lb/hr)			*optional input*
Gas Volume		(dscfm)			*optional input*
2 Full Load Engine Exhaust Composition:					**Comments**
Oxygen (O_2)		(vol. %)			*optional input*
Carbon Dioxide (CO_2)		(vol. %)			*optional input*
Water (H_2O)		(vol. %)			*optional input*
Oxides of Nitrogen (NOx)		(ppmvd)			*optional input*
Nitrogen (N_2)		(vol. %)			*optional input*
NOx	52.7	lb/hr	0.366	(lb/MMBtu)	NOx emissions from test Data: 373.0 lb/MMSCF ~0.37 lb/MMBtu
3 Engine Parameters					**Comments**
Total Operating Hours per Season	8760	(hrs)	100%	utilization	
4 Final Exhaust Gas Composition					**Comments**
Oxides of Nitrogen (NOx)	13.2	lb/hr	0.092	(lb/MMBtu)	Assume 75% reduction
5 Economic Parameters					**Comments**
Source of Cost Data	see Analysis				Analysis primarily relying on EPA Cost Manual
Direct Costs		**Cost Formula**			**Comments**
Combustion Control Equipment and Auxiliary Equipment	$3,712,500	(A)			Based on EPA control cost manual ($167/kw ; adjust to 2020$)
Instrumentation	$371,250	(0.1*A)			Calculated Cost using EPA Control Cost Manual
Sales Taxes	$122,513	(0.03*(A+instrumentation))			3% Sales Tax in this example
Freight	$185,625	(0.05*A)			Calculated Cost using EPA Control Cost Manual
Purchased Equipment Cost (PEC)	**$4,391,888**	PEC			
6 Direct Installation Costs		**Cost Formula**			**Comments**
Foundations and Supports	$351,350	(0.08*PEC)			Calculated Cost using EPA Control Cost Manual
Handling and Erection	$614,860	(0.14*PEC)			Calculated Cost using EPA Control Cost Manual
Electrical	$175,680	(0.04*PEC)			Calculated Cost using EPA Control Cost Manual
Piping	$87,840	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
Insulation for ductw ork	$43,920	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Painting	$43,920	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Site Preparation	$0	SP			As required
Buildings	$0	Bldg			As required
Total Installation Cost (TIC)	**$1,317,570**				
Total Direct Costs (PEC+TIC)	**$5,709,458**				

Table 1 (continued).

7	**Indirect Costs**		**Cost Formula**			**Comments**
	Engineering	$439,189	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
	Construction and field expenses	$219,594	(0.05*PEC)			Calculated Cost using EPA Control Cost Manual
	Contractor fees	$439,189	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
	Start-up	$87,838	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
	Performance test	$43,919	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
	Contingencies	$131,757	(0.03*PEC)			Calculated Cost using EPA Control Cost Manual
	Total Indirect Costs (IC)	**$1,361,485**	(0.31*PEC)			
8	**Capital Cost Summary**					**Comments**
	Total Direct Capital Costs (DC)	$5,709,458				
	Total Indirect Capital Costs (IC)	$1,361,485				
	Total Capital Investment (TCI)	**$7,070,943**				
9	**Direct Annual Costs**		**Cost Formula**			**Comments**
	Operator Labor	$12,500	nominal cost			0.5 hr/shift; example from similar EPA analysis
	Supervisor Labor	$1,875				15% of operator
	Operating Materials - ammonia	$54,289				materials estimate annual NH3 at $700 per ton; 1.1 molar ratio
	Maintenance - Labor	$12,500	nominal cost			0.5 hr/shift; rate example from EPA
	Maintenance - Materials	$5,000	nominal cost			Engineering Estimate
	Catalyst maintenance / replacement	$185,625				Engineering Estimate (5% of Cap Cost)
	Testing and QA/QC	$20,000				Engineering estimate - Annual test; reagent controller QA
	Electricity	$2,500				Estimate based on analysis in PA DEP TSD
	Total Direct Annual Costs	**$294,289**				
10	**Indirect Annual Costs**		**Cost Formula**	**Capital Recovery Factor**		**Comments**
	Overhead	$19,125	(0.6*(OL+SL+ML+MM))			
	Administrative Charges	$141,419	(0.02*TCI)			Engine ACT Document
	Property Taxes	$70,709	(0.01*TCI)			Engine ACT Document
	Insurance	$70,709	(0.01*TCI)		**CRF**	
	Capital Recovery	$567,090	CRF[TCI]		0.0802	Factor for costs annualized over 20 years at 5% interest.
	Total Indirect Annual Costs	**$869,052**			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)	
11	**Summary**					**Comments**
	Total Direct Annual Operating Costs	$294,289				
	Total Indirect Annual Operating Costs	$869,052				
	Total Annual Costs	$1,163,342		$61	$ per hp	
	Incremental Annual Costs Over Baseline	$1,163,342				
12	**Annual Emissions Reduction Over Baseline**					**Comments**
	Oxides of Nitrogen (NOx)	173.13	(Tons)			
	Cost Effectiveness ($/Ton)					**Comments**
	Oxides of Nitrogen (NOx)	$6,719				

Table 2. Rolls Royce Avon Turbine (Unit 12B) SCR NOx Control Cost Effectiveness (100% utilization case).

NOx Control Cost Effectiveness Estimate

Engine Manufacturer	Cooper-Rolls				
Model No.	Avon				
Unit ID	12B				
Fuel Used	Natural Gas				**Color Legend**
Emissions Control	SCR				User Data / Information Input Cell
Combustion Control Purpose	NOx				"Cumulative" Cost Cell for Primary Categories
Target Reduction	75%				Cost Effectiveness ($ / ton)

1 Engine Design Conditions					**Comments**
Power Output	14300	(hp)			Rated HP
Engine Exhaust Temperature		(F)			*optional input*
Engine Exhaust Rate		(lb/hr)			*optional input*
Gas Volume		(dscfm)			*optional input*
2 Full Load Engine Exhaust Composition:					**Comments**
Oxygen (O_2)		(vol. %)			*optional input*
Carbon Dioxide (CO_2)		(vol. %)			*optional input*
Water (H_2O)		(vol. %)			*optional input*
Oxides of Nitrogen (NOx)		(ppmvd)			*optional input*
Nitrogen (N_2)		(vol. %)			*optional input*
NOx	23.1	lb/hr	0.170	(lb/MMBtu)	NOx emissions from test Data: 173.9 lb/MMSCF ~0.170 lb/MMBtu
3 Engine Parameters					**Comments**
Total Operating Hours per Season	8760	(hrs)	100%	utilization	
4 Final Exhaust Gas Composition					**Comments**
Oxides of Nitrogen (NOx)	5.8	lb/hr	0.043	(lb/MMBtu)	Assume 75% reduction
5 Economic Parameters					**Comments**
Source of Cost Data	see Analysis				Analysis primarily relying on EPA Cost Manual
Direct Costs		**Cost Formula**			**Comments**
Combustion Control Equipment and Auxiliary Equipment	$2,765,000	(A)			Based on EPA control cost manual ($167/kw ; adjust to 2020$)
Instrumentation	$276,500	(0.1*A)			Calculated Cost using EPA Control Cost Manual
Sales Taxes	$91,245	(0.03*(A+instrumentation))			3% Sales Tax in this example
Freight	$138,250	(0.05*A)			Calculated Cost using EPA Control Cost Manual
Purchased Equipment Cost (PEC)	**$3,270,995**	PEC			
6 Direct Installation Costs		**Cost Formula**			**Comments**
Foundations and Supports	$261,680	(0.08*PEC)			Calculated Cost using EPA Control Cost Manual
Handling and Erection	$457,940	(0.14*PEC)			Calculated Cost using EPA Control Cost Manual
Electrical	$130,840	(0.04*PEC)			Calculated Cost using EPA Control Cost Manual
Piping	$65,420	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
Insulation for ductwork	$32,710	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Painting	$32,710	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Site Preparation	$0	SP			As required
Buildings	$0	Bldg			As required
Total Installation Cost (TIC)	**$981,300**				
Total Direct Costs (PEC+TIC)	**$4,252,295**				

Table 2 (continued).

					Comments
7 Indirect Costs		**Cost Formula**			**Comments**
Engineering	$327,100	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
Construction and field expenses	$163,550	(0.05*PEC)			Calculated Cost using EPA Control Cost Manual
Contractor fees	$327,100	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
Start-up	$65,420	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
Performance test	$32,710	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Contingencies	$98,130	(0.03*PEC)			Calculated Cost using EPA Control Cost Manual
Total Indirect Costs (IC)	**$1,014,008**	(0.31*PEC)			
8 Capital Cost Summary					**Comments**
Total Direct Capital Costs (DC)	$4,252,295				
Total Indirect Capital Costs (IC)	$1,014,008				
Total Capital Investment (TCI)	**$5,266,303**				
9 Direct Annual Costs		**Cost Formula**			**Comments**
Operator Labor	$12,500	nominal cost			0.5 hr/shift; example from similar EPA analysis
Supervisor Labor	$1,875				15% of operator
Operating Materials - ammonia	$23,789				materials estimate annual NH3 at $700 per ton; 1.1 molar ratio
Maintenance - Labor	$12,500	nominal cost			0.5 hr/shift; rate example from EPA
Maintenance - Materials	$5,000	nominal cost			Engineering Estimate
Catalyst maintenance / replacement	$138,250				Engineering Estimate (5% of Cap Cost)
Testing and QA/QC	$20,000				Engineering estimate - Annual test; reagent controller QA
Electricity	$2,500				Estimate based on analysis in PA DEP TSD
Total Direct Annual Costs	**$216,414**				
10 Indirect Annual Costs		**Cost Formula**		**Capital Recovery Factor**	**Comments**
Overhead	$19,125	(0.6*(OL+SL+ML+MM))			
Administrative Charges	$105,326	(0.02*TCI)			Engine ACT Document
Property Taxes	$52,663	(0.01*TCI)			Engine ACT Document
Insurance	$52,663	(0.01*TCI)		**CRF**	
Capital Recovery	$422,358	CRF[TCI]		0.0802	Factor for costs annualized over 20 years at 5% interest.
Total Indirect Annual Costs	**$652,135**			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)	
11 Summary					**Comments**
Total Direct Annual Operating Costs	$216,414				
Total Indirect Annual Operating Costs	$652,135				
Total Annual Costs	$868,549		$61	$ per hp	
Incremental Annual Costs Over Baseline	$868,549				
12 Annual Emissions Reduction Over Baseline					**Comments**
Oxides of Nitrogen (NOx)	75.87	(Tons)			
Cost Effectiveness ($/Ton)					**Comments**
Oxides of Nitrogen (NOx)	$11,449				

Table 3. Solar Titan Turbine (Unit 12C) SCR NOx Control Cost Effectiveness (100% utilization case).

NOx Control Cost Effectiveness Estimate

Engine Manufacturer	Solar
Model No.	Titan
Unit ID	12C
Fuel Used	Natural Gas
Emissions Control	SCR
Combustion Control Purpose	NOx
Target Reduction	60%

Color Legend
User Data / Information Input Cell
"Cumulative" Cost Cell for Primary Categories
Cost Effectiveness ($ / ton)

1 Engine Design Conditions					**Comments**
Power Output	19500	(hp)			Rated HP
Engine Exhaust Temperature		(F)			*optional input*
Engine Exhaust Rate		(lb/hr)			*optional input*
Gas Volume		(dscfm)			*optional input*
2 Full Load Engine Exhaust Composition:					**Comments**
Oxygen (O_2)		(vol. %)			*optional input*
Carbon Dioxide (CO_2)		(vol. %)			*optional input*
Water (H_2O)		(vol. %)			*optional input*
Oxides of Nitrogen (NOx)		(ppmvd)			*optional input*
Nitrogen (N_2)		(vol. %)			*optional input*
NOx	6.8	lb/hr	0.052	(lb/MMBtu)	NOx emissions from test Data: 52.6 lb/MMSCF ~0.052 lb/MMBtu
3 Engine Parameters					**Comments**
Total Operating Hours per Season	8760	(hrs)	100%	utilization	
4 Final Exhaust Gas Composition					**Comments**
Oxides of Nitrogen (NOx)	2.7	lb/hr	0.021	(lb/MMBtu)	Assume 60% reduction for unit equipped with DLE combustion
5 Economic Parameters					**Comments**
Source of Cost Data	see Analysis				Analysis primarily relying on EPA Cost Manual
Direct Costs		**Cost Formula**			**Comments**
Combustion Control Equipment and Auxiliary Equipment	$3,770,500	(A)			Based on EPA control cost manual ($167/kw ; adjust to 2020$)
Instrumentation	$377,050	(0.1*A)			Calculated Cost using EPA Control Cost Manual
Sales Taxes	$124,427	(0.03*(A+instrumentation))			3% Sales Tax in this example
Freight	$188,525	(0.05*A)			Calculated Cost using EPA Control Cost Manual
Purchased Equipment Cost (PEC)	**$4,460,502**	PEC			
6 Direct Installation Costs		**Cost Formula**			**Comments**
Foundations and Supports	$356,840	(0.08*PEC)			Calculated Cost using EPA Control Cost Manual
Handling and Erection	$624,470	(0.14*PEC)			Calculated Cost using EPA Control Cost Manual
Electrical	$178,420	(0.04*PEC)			Calculated Cost using EPA Control Cost Manual
Piping	$89,210	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
Insulation for ductwork	$44,610	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Painting	$44,610	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Site Preparation	$0	SP			As required
Buildings	$0	Bldg			As required
Total Installation Cost (TIC)	**$1,338,160**				
Total Direct Costs (PEC+TIC)	**$5,798,662**				

Table 3. (continued)

7 Indirect Costs		**Cost Formula**			**Comments**
Engineering	$446,050	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
Construction and field expenses	$223,025	(0.05*PEC)			Calculated Cost using EPA Control Cost Manual
Contractor fees	$446,050	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
Start-up	$89,210	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
Performance test	$44,605	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Contingencies	$133,815	(0.03*PEC)			Calculated Cost using EPA Control Cost Manual
Total Indirect Costs (IC)	**$1,382,755**	(0.31*PEC)			
8 Capital Cost Summary					**Comments**
Total Direct Capital Costs (DC)	$5,798,662				
Total Indirect Capital Costs (IC)	$1,382,755				
Total Capital Investment (TCI)	**$7,181,417**				
9 Direct Annual Costs		**Cost Formula**			**Comments**
Operator Labor	$12,500	nominal cost			0.5 hr/shift; example from similar EPA analysis
Supervisor Labor	$1,875				15% of operator
Operating Materials - ammonia	$7,045				materials estimate annual NH3 at $700 per ton; 1.1 molar ratio
Maintenance - Labor	$12,500	nominal cost			0.5 hr/shift; rate example from EPA
Maintenance - Materials	$5,000	nominal cost			Engineering Estimate
Catalyst maintenance / replacement	$188,525				Engineering Estimate (5% of Cap Cost)
Testing and QA/QC	$20,000				Engineering estimate - Annual test; reagent controller QA
Electricity	$2,500				Estimate based on analysis in PA DEP TSD
Total Direct Annual Costs	**$249,945**				
10 Indirect Annual Costs		**Cost Formula**	**Capital Recovery Factor**		**Comments**
Overhead	$19,125	(0.6*(OL+SL+ML+MM))			
Administrative Charges	$143,628	(0.02*TCI)			Engine ACT Document
Property Taxes	$71,814	(0.01*TCI)			Engine ACT Document
Insurance	$71,814	(0.01*TCI)		**CRF**	
Capital Recovery	$575,950	CRF[TCI]		0.0802	Factor for costs annualized over 20 years at 5% interest.
Total Indirect Annual Costs	**$882,331**			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)	
11 Summary					**Comments**
Total Direct Annual Operating Costs	$249,945				
Total Indirect Annual Operating Costs	$882,331				
Total Annual Costs	$1,132,276		$58	$ per hp	
Incremental Annual Costs Over Baseline	$1,132,276				
12 Annual Emissions Reduction Over Baseline					**Comments**
Oxides of Nitrogen (NOx)	17.97	(Tons)			
Cost Effectiveness ($/Ton)					**Comments**
Oxides of Nitrogen (NOx)	$62,996				

Table 4. 2017 – 2019 Operating Hours and Fuel Use for Station 12 Turbines.

Year	Unit	Hours	Fuel Used (MMscf)	Annual Average Hourly Fuel Rate (Mscfh)
2017	12A	1,835	158.2	86.2
2018	12A	1,470[A]	146.7	99.8
2019	12A	1,996	203.9	102.0
2017	12B	1,563	172.6	110.4
2018	12B	2,425	268.7	110.8
2019	12B	1,689	183.0	108.4
2017	12C	6,365	744.8	117.0
2018	12C	8,528	964.3	113.1
2019	12C	6,145	716.7	116.6

[A] The value reported in the 2018 emission inventory (2,119.75 hours) was found to be erroneous. The corrected value is shown.