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CONTROL TECHNOLOGIES REVIEW FOR GAS TURBINES IN SIMPLE CYCLE, COMBINED CYCLE AND COGENERATION INSTALLATIONS

Final Report

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LIST OF ACRONYMS

Acronym	Definition
A/F	Air to fuel
BACT	Best Achievable Control Technology
BACTEA	Best Achievable Control Technology Economically Achievable
CASA	Clean Air Strategic Alliance
CFD	Computational Fluid Dynamics
CFR	Code of Federal Regulation
CH4	Methane
CHP	Cogeneration or combined heat and power
CO	Oxidize carbon monoxide
CO2	Carbon dioxide
DLE	Dry low emissions
DLN	Dry low-NO_x
DOE	Department of Energy
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
GTW	Gas Turbine World
GWP	Global Warming Potentials
H_2	Hydrogen
HC	Hydrocarbons
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
kW	Kilowatt
KNO_3	Potassium nitrates
NH_3	Ammonia
NO	Nitric oxide
NO_X	Nitrogen oxide
NSCR	Non-selective Catalytic Reduction
ppm	Parts per million
ppmvd	Parts per million by volume density
ppmv	Parts per million by volume
PSD	Prevention of Significant Determination
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RQL	Rich burn, quick-mix, lean burn
SCR	Selective Catalytic Reduction
SNCR	Selective Non-catalytic Reduction
TAC	Total annual costs
TCEQ	Texas Commission on Environmental Quality
TCI	Total capital investment
TVC	Trapped vortex combustion
VOC	Volatile organic compound

1.0 INTRODUCTION

In 2009, ERG completed a review of emission control measures for electricity generation technologies for the Clean Air Strategic Alliance (CASA). The review was documented in a report entitled *Electricity Framework 5 Year Review – Control Technologies Review, Final Report* (January 21, 2009). The 2009 Report included an assessment of controls for coal-fired boilers and gas-fired turbines, as well as other information, such as future generation technologies, fuels, and control measures. As requested by CASA, ERG has now completed a review to update simple and combined cycle turbine control technologies. In addition, we have evaluated additional issues unique to co-generation installations. We investigated both operational and economic issues associated with co-generation, including those involving the Heat Recovery Steam Generation (HRSG) portion of co-generation units.

This report also includes an evaluation of environmental variables that effect emission generation and control, including:

1. The impacts of start-up and shut-down on gas turbines.

2. The impact of partial loading.

3. The implications of varying gas composition.

4. The implications of size cut-offs, such as interruption in supply or equipment availability.

5. Advances in duct firing.

The report is divided into 6 additional sections. In Section 2.0, the methodology used for evaluating the various control technologies is presented and Section 3.0 provides the assessment of the gas turbine nitrogen oxides (NO_x) emission control technologies. In this section, we have listed potential emission controls, identified pollutant removal effectiveness, assessed feasibility, control costs, environmental and safety impacts, and potential co-benefits of the specific controls. Retrofit technologies for existing turbines were not assessed in this document. Section 4.0 discusses additional considerations associated with co-generation and combined cycle installations and advances in duct firing. Section 5.0 provides an analysis of Sulphur Dioxide (SO_2) from alternative gas fuels. Section 6.0 includes additional parameters that effect emissions levels, such as start-up and shutdown, partial lead, varying gas composition, and size cut-offs. Section 7.0 includes a discussion of the actual permitted limits of turbine installations and assesses achievable emission limits. We also provide information on units that may need to be addressed on a case-by-case basis in Section 7.0.

2.0 METHODOLOGY FOR CONTROL TECHNOLOGY EVALUATION

ERG evaluated the possible control technologies for controlling emissions from gas turbines using an accepted procedure similar to the procedure for establishing Best Available Control Technology-Economically Achievable (BACTEA) under Ontario Regulation 194/05 and for conducting a Best Achievable Control Technology (BACT) analysis that is required for Prevention of Significant Determination (PSD) permits under United States Environmental Protection Agency (EPA) regulations. In summary, the analysis consisted of the following six steps:

- Identify applicable control technologies
- Eliminate technically infeasible technologies
- Rank control technologies
- Determine control costs and emission reductions
- Assess environmental and safety concerns
- Evaluate co-benefits

The following discussion describes the considerations made for each step in the process.

2.1 Identify Applicable Control Technologies

All available control technologies potentially applicable to NO_x control in turbines were identified from various data sources, including the following:

- EPA's Reasonably Available Control Technology /BACT/Lowest Achievable Emission Reductions (RACT/BACT/LAER) or RBLC clearinghouse.[1]
- Specific air permits, permit applications, BACT analyses, technical support documents for issued permits for U.S. facilities.
- New data available from U.S. EPA's Mercury and Air Toxics Standards. These standards are primarily directed to control coal-fired electricity generating units, however, the data collected was reviewed for data applicable to gas-fired turbines.
- Vendor information from literature and websites.
- Technical reviews and journals including reports of actual operating experience. For example, Power Magazine and Power Engineering often provide up-to-date and authoritative information on controls for power plants.
- U.S. Department of Energy, National Energy Technology Laboratory – Office of Systems, Analyses and Planning who attempt to establish baseline performance and cost estimates for modern fossil energy plants.
- Gas Turbine World – GTW Handbook.

2.2 Eliminate Technically Infeasible Technologies

Following identification of the potential control technologies, the list was revised by removing those technologies that were considered technically infeasible. Specifically technologies were eliminated because they have not been demonstrated at comparable facilities

[1] http://cfpub.epa.gov/rblc/

in North America or they are not commercially available for the size range expected for utility and industrial applications in Alberta.

2.3 Rank Control Technologies

In this step the technologies that are considered feasible are ranked from best performance (lowest emissions) to worst performance.

2.4 Determine Control Costs and Emission Reductions

Costs and emission reductions for applying the control was estimated by using model units. Model units were developed to represent the potential variations in operating parameters (such as size and hours of operation) of new gas-fired turbines that are most likely to be constructed in Alberta.

2.4.1 *Costs*

Costs are presented as total capital investment (TCI) and total annual costs (TAC) in U.S. dollars ($). TCI is expressed in dollars, dollars per kilowatt (kW), and dollar per life of the control device ($MW\text{-}hr_{lifetime}$), and consists of the following:

- Purchased equipment costs – control device costs, auxiliary equipment costs, instrumentation, sales taxes, and freight.
- Direct installation costs – foundations and support, handling and erection, electrical, piping, insulation, and painting.
- Site preparation.
- Working capital.
- Indirect installation costs – engineering, construction and field expenses, contractor fees, start-up, and contingencies.

TAC is expressed in dollars per year and consists of the following:

- Operating costs – raw materials, utilities, waste treatment/disposal, labor, and maintenance.
- Indirect costs – overhead, property taxes, insurance, administrative charges, and capital recovery.

The various cost values (e.g., cost of capital, raw material, utilities and labour) were collected from several different sources listed in Section 2.1. Cost factors and cost components are based on those provided in the EPA's Control Cost Manual 6th Edition (2002)[2]. All costs were adjusted to 2013 dollars. Additional details on costs are included in Section 3.4.

Capital recovery was calculated assuming the control equipment has a 20-year life at an interest rate of 7 percent. Construction and operating labour costs were assumed to be

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[2] EPA Air Pollution Control Cost Manual – Sixth Edition (EPA/452/B-02-001). Research Triangle Park, NC: Office of Air Quality Planning and Standards, 2002. Mussatti, Daniel C, ed. Web. 25 May 2014. <http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf>.

C$100/hour. The labour rate is based on a recent publication specific to labour rates in Alberta[3] and represents the average of rates for construction labourers and operating engineers and includes a factor for per diem subsistence, premium time, overhead, taxes and a productivity factor to adjust for the additional time it takes to work in a remote area (e.g. to secure special equipment or tools) The labour rate was developed by CASA.

2.4.2 *Emission Reductions*

Emission reductions for each of the model facilities were calculated by applying the control effectiveness for the control technology to the baseline emissions from the emission source (turbine). Baseline emissions of NO_x were calculated for each model by applying the emission level associated with the baseline control technology that is expected at newly constructed units.

2.5 Assess Environmental and Safety Concerns

In addition to reduction of NO_x emissions, other environmental impacts were evaluated to determine the extent of impacts caused by the operation of a control technology. Examples of environmental impacts include water use, polluted water discharges, solid waste generation, such as spent catalyst, and additional air pollutants created (i.e., ammonia emissions). The energy consumed by control option auxiliary equipment (e.g., running motors, fans, pumps) and the resulting potential greenhouse gas emissions were also calculated.

2.6 Evaluate Co-benefits

Actions to reduce a target pollutant may affect emissions of other pollutants or may generate other benefits. These co-benefits will be considered in the analysis.

[3] Wage Summary: Construction – Alberta 2011-2015. Prepared by Construction Labour Relations. March 12, 2014.

3.0 ANALYSIS OF COMBUSTION TURBINE CONTROL TECHNOLOGY

NO_x formation in gas turbines occurs by three mechanisms. The principal mechanism is thermal NO_x, which arises from the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most thermal NO_x is formed in high-temperature flame pockets downstream of the fuel injectors, typically at temperatures greater than 1500°C.[4] The second mechanism, prompt NO_x, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. The third mechanism, fuel NO_x, stems from the reaction of fuel-bound nitrogen compounds with oxygen. The relative importance of these mechanisms in contributing to overall NO_x emission depends largely upon combustor operating conditions and the presence of fuel-bound nitrogen. Natural gas has negligible chemically bound fuel nitrogen (although some molecular nitrogen is present). Therefore, essentially all NO_x formed from natural gas combustion is thermal NO_x.

Conventional turbine combustors are diffusion-controlled, where fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces, resulting in hot spots that produce high levels of NO_x. In contrast, lean premixed combustors (also known as dry low-NO_x or DLN[5] combustors) mix the fuel and air at a lean "air-to-fuel" (A/F) ratio prior to injection into the combustion zone. Because the fuel is combusted with excess air, peak combustion temperatures and thermal NO_x are reduced. Based on the 2013 Gas Turbine World,[6] DLN systems are considered "standard" equipment on gas turbines. Therefore, DLN is considered baseline control for this analysis. The majority of commercially available DLN combustors achieve NO_x reduction to 25 parts per million by volume dry (ppmvd) corrected to 15% oxygen with NO_x guarantees as low as 3 to 5 ppmv can be obtained,[7] although 15 and 9 ppmv are more common lower NO_x guarantees. [All references to ppm or ppmv in this document, refer to ppmvd to 15% oxygen.] It has been assumed in this analysis that the baseline level of control for turbines is one having DLN and emitting 25 ppmv.

The analysis was conducted for control technologies used to reduce NO_x for both simple and combined-cycle combustion turbines and for cogeneration systems. Small combustion turbines (less than 25 MW) have been excluded from the analysis because they are not expected to be used by electrical utilities or cogeneration installation at industrial facilities.

This section presents ERG's analysis using the control technology evaluation methodology described in Section 2.

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4 Liewwen, Tim C. and Vigor Yang, editors, "Gas Turbine Emissions", Chapter 7: NO_x and CO Formation and Control.

5 This is also referred to as dry low emissions (DLE). This report will use the term DLN for consistency.

6 2013 Gas Turbine World Handbook (Volume 30). Pequot Publishing, 2013. Farmer, Robert, ed. http://www.gasturbineworld.com/. Web. August 2014.

7 GE Energy, Heavy Duty Gas Turbine Product brochure, 2009 http://www.ge-energy.com/content/multimedia/_files/downloads/dataform_2046207337_2809806.pdf

3.1 Identify Control Technologies

Since the 2009 Report[8] was developed, turbine manufacturers have continued to refine their designs and improve on many aspects. Though many of the turbine combustor configurations and other emission control technologies, such as DLN, were conceptualized or introduced decades ago, they continue to evolve and improve. As the deployment of gas combustion turbines for power generation continues to increase, so does the need to further reduce their emissions. New generations of old technologies continue to evolve and improve emissions from combustion turbines, including: trapped vortex combustion (TVC); rich burn, quick-mix, lean burn (RQL); staged air combustion (e.g., COSTAIR); mild combustion; and surface stabilized combustion.[9] As an example, this year GE introduced two new versions of its H-class turbine – a design that was first introduced over 10 years ago. These new versions offer DLN combustors, startup times to full power in as little as 10 minutes, and combined cycle efficiency over 61% (41% efficiency in simple cycle operation).[10] All of these elements combine to reduce emissions considerably.

In the 2009 Report, it was assumed that the baseline level of control for all new turbines would be DLN systems with emissions of 25 ppmv or less of NO_x, or wet injection achieving similar results. The baseline level of control establishes the basis for assessing the emission reductions and control costs associated with applying the additional controls. Prior to identifying potential emission reduction technologies, the assumed baseline level of control must be determined. Throughout this analysis, it has also been assumed that DLN burners would be standard on any turbine purchased for electric generation. For the large, heavy-duty turbines, this is clearly true. For example, GE Energy, Siemens, Alstom, and Mitsubishi all manufacture their largest turbines with DLN systems as standard equipment. Even for the smaller turbines in the range of 25 to 50 MW, many have DLN burners as standard or at least as an alternative.

The remainder of this section identifies control technologies that can be implemented in addition to or, in some cases, instead of DLN to reduce NO_x emissions for turbines firing natural gas. Seven control technologies were identified:

1. DLN with Catalytic Combustion

Catalytic technology features "flameless" combustion that occurs in a series of catalytic reactions to limit the temperature in the combustor. This allows complete mixing of the fuel and air, with the combustion initiated by a catalytic surface and occurring at temperatures below those at which measurable amounts of NO_x form. This technology was originally developed by Calytica Combustion Systems, Inc. and was purchased by Kawaski in August 2006. Kawaski uses this technology in their turbine model GPX15X, a 1.4 MW turbine with NO_x emissions of

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8 ERG, 2009, *Electricity Framework 5 Year Review – Control Technologies Review, Final Report* (January 21, 2009), for the Clean Air Strategic Alliance.

9 el_Hossaini, M. Khosravy, 2013. Review of the New Combustion Technologies in Modern Gas Turbines, Progress in Gas Turbine Performance, Dr. Ernesto Benini (Ed.), ISBN: 978-953-51-1166-5, InTech, DOI: 10.5772/54403. Available from: http://www.intechopen.com/books/progress-in-gas-turbine-performance/review-of-the-new-combustion-technologies-in-modern-gas-turbines.

10 Overton, Thomas W., "Recent Innovations from Gas Turbine and HRSG OEMs", POWER, Vol. 158 No. 6, June 2014.

2.5 ppm at 15% oxygen.[11] In testing performed in 2000 on a similar turbine, NO_x emissions were measured at 1.13 ppmvd @ 15% oxygen.[12] This is the same sized unit Kawasaki was selling in 2006. No other manufacturer makes a commercially available flameless combustor.[13]

2. Ultra Dry Low NO_x

There are several turbines manufactured that can achieve NO_x emissions lower than 25 ppmv. There are various terms used by the manufacturers to refer to these combustors. In this report, they will be referred generally as ultra dry low NO_x (UDLN) turbines and will refer to any turbine that the vendor advertises as able to achieve NO_x emissions of 15 ppmv or less. There were no vendor performance claims found between 25 and 15 ppmv. Vendors referenced performance for UDLN of 15, 9, 5, and 4 ppmv of NO_x. Table 3-1 provides a list of turbines from the primary turbine manufacturers (i.e., GE, Siemens, Alstom, Mitsubishi, and Rolls Royce) with DLN or UDLN combustors and the published vendor performance levels. This is a list of the turbine models for which performance levels could be identified or inferred. Although this is not an extensive list of available DLN and UDLN turbines, it is believed to represent the majority of available units. Over half of the models shown have UDLN performance, with most of these being 15 ppmv.

Table 3-1. Available DLN and UDLN Turbines

Manufacturer	Frequency	Model	MW	NO_x level
Kawasaki Heavy Industries		L30A	30	15
Hitachi	50/60	H-25	32	15
Siemens Energy	50/60	SGT-700	32	15
Siemens Energy	50/60	SGT-750	36	15
GE Heavy Duty	50/60	6B 3-series	43	4
GE Energy Aeroderivative	60	LM6000PF	43	15
GE Energy Aeroderivative	50	LM6000PF	43	15
GE O&G	50/60	LM6000PF	43	15
GE Energy Aeroderivative	50	LM6000PF Sprint	48	15
GE Energy Aeroderivative	60	LM6000PF Sprint	48	15
Siemens Energy	50/60	SGT-800 (option 1)	48	15
GE Energy Aeroderivative	50	LM6000PH	51	15
GE Energy Aeroderivative	60	LM6000PH	51	15
Siemens Energy	50/60	SGT-800 (option 2)	51	15
GE Energy Aeroderivative	50	LM6000PH Sprint	53	15
GE Energy Aeroderivative	60	LM6000PH Sprint	53	15
GE Heavy Duty	50/60	6F 3-series	78	15
GE Heavy Duty	60	7E 3-series	89	4

[11] Kawasaki Gas Turbine Generator Sets brochure, May 2010. Accessed May 23, 2014 at: http://www.kawasakigasturbines.com/brochures/GPBSALESBROCHURE.pdf.

[12] EPRI. Xonon® Low-NO_x Catalytic Combustion in Practice: Case Study of a 1,400 kW Combustion Turbine. EPRI, Palo Alto, CA; CEC, Sacramento, CA; and SDC, Eldridge, CA: 2006. 1013143.

[13] Green Gas Turbines in CHP, presented by Steve Cernik of Kawasaki at the CATEE Workshop in Plano Texas, December 15, 2008.

Table 3-1. Available DLN and UDLN Turbines

Manufacturer	Frequency	Model	MW	NO_x level
Hitachi	60	H-80	111	15
Hitachi	50	H-80	112	15
GE Heavy Duty	50	9E 3-series	128	5
Mitsubishi	60	M501F3	185	9 or 15
Alstrom	50	GT13E2	203	15
GE Heavy Duty	60	7F 5-series	216	9
Alstrom	60	GT24	231	15
Siemens Energy	60	SGT6-5000F	232	9
GE Heavy Duty	50	9F 3-series	261	15
Mitsubishi	60	M501G1	268	15
Mitsubishi	60	M501GAC	276	15
Mitsubishi	50	M701F3	312	9 or 15
Mitsubishi	50	M701F4	324	15
Alstrom	50	GT26	326	15
Mitsubishi	50	M701G2	334	15
Mitsubishi	50	M701F5	359	15
Siemens Energy	50/60	SGT-600	25	25
Rolls Royce	50/60	RB211-G62 DLE	27	25
GE Energy Aeroderivative	60	LM2500PR	30	25
GE Energy Aeroderivative	50	LM2500PR	30	25
Rolls Royce	50/60	RB211-GT62 DLE	30	25
Rolls Royce	50/60	RB211-GT61 DLE	32	25
GE O&G	50/60	PGT25+G4	33	25
GE Energy Aeroderivative	50	LM6000PD	43	25
GE Energy Aeroderivative	60	LM6000PD	43	25
GE O&G	50/60	LM6000PD	43	25
GE Energy Aeroderivative	60	LM6000PD Sprint	47	25
GE Energy Aeroderivative	50	LM6000PD Sprint	48	25
Rolls Royce	50	Trent 60 DLE	53	25
Rolls Royce	60	Trent 60 DLE	54	25
Rolls Royce	60	Trent 60 DLE ISI	62	25
Rolls Royce	50	Trent 60 DLE ISI	64	25
GE Energy Aeroderivative	60	LMS100PB	99	25
GE Energy Aeroderivative	50	LMS100PB	100	25
Siemens Energy	60	SGT6-2000E	112	25
Alstrom	50	GT11N2	114	25
Alstrom	60	GT11N2	115	25
Siemens Energy	50	SGT5-2000E	166	25
Siemens Energy	60	SGT6-8000H	274	25
Siemens Energy	50	SGT5-4000F	292	25

Table 3-1. Available DLN and UDLN Turbines

Manufacturer	Frequency	Model	MW	NO_x level
GE Heavy Duty	50	9F 5-series	298	25
Siemens Energy	50	SGT5-8000H	375	25

The UDLN turbines are manufactured by several different companies. Of the major turbine manufacturers Rolls Royce seems to be the only manufacturer that does not currently have an UDLN turbine on the market.

It appears that UDLN turbines are available across the full range of turbine sizes, although DLN are available on a slightly wider range. They are available starting at 30 MW, while DLN are available starting at 25 MW; and there are UDLN up to 359 MW, while DLN are available up to 375 MW.

Table 3-1 shows that UDLN turbines are feasible and available.

3. Non-selective Catalytic Reduction (NSCR)

NSCR technology is designed to simultaneously reduce NO_x and oxidize carbon monoxide (CO) and hydrocarbons (HCs) in the combustion gas to nitrogen, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen [H_2], methane [CH_4], and CO) to reduce both nitric oxide (NO) and nitrogen dioxide (NO_2) to nitrogen at a temperature between 430°C and 650°C. To be effective, NSCR requires a low excess oxygen concentration in the exhaust gas stream because the oxygen must be depleted before the reduction chemistry can proceed.

4. SCONOx™

SCONOx™ is an oxidation catalyst-based technology that removes both NO_x and CO without the need for supplementary chemical reagents, such as ammonia (NH_3). The SCONOx™ catalytic absorption system uses a potassium carbonate-coated catalyst to reduce NO_x emissions. The catalyst oxidizes CO to CO_2 and NO to NO_2 and potassium nitrates (KNO_3). The catalyst is regenerated by passing dilute hydrogen gas through the catalyst, which converts the KNO_2 and KNO_3 to K_2CO_3, water, and elemental nitrogen. The catalyst is renewed and available for further absorption, while the water and nitrogen are exhausted. The $SCONO_x$ system has demonstrated its ability to meet the same low emission rates as a conventional SCR/CO oxidation catalyst system without the use of NH_3. EMx™ (the second-generation of the $SCONO_x$™ NO_x Absorber technology) has been commercially demonstrated on several small (5 MW) gas turbines and a single 45 MW gas turbine in Redding, California, with NO_x emissions below 1.5 ppmv. [14]

5. Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in the turbine exhaust stream to molecular nitrogen, water, and oxygen. In the SCR process, aqueous or anhydrous NH_3 is used as the reducing agent and is injected into the flue gas upstream of the

[14] EmeraChem, LLC. Multi-Pollutant Emission Reduction Technology For Stationary Gas Turbines and IC Engines Revision 1. January 5, 2004.

catalyst bed. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction. NO_x and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Increasing this ratio will not only further reduce NO_x emissions, but also will result in increased unreacted NH_3 that "slips" through the process into the atmosphere. Removal efficiencies are generally 80 to 95 percent. The California Air Resources Board - BACT Clearinghouse shows that a SCR system installed on a combined-cycle aeroderivative gas fired turbine can achieve an exhaust gas NO_x concentration of 1.45 ppmv.[15]

The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Base metal catalysts have an operating temperature window for clean fuel applications of approximately 260° to 426°C.

Turbines that operate in simple-cycle mode have exhaust gas temperatures ranging from approximately 450°C to 540°C. For a base metal catalyst to be used on a simple-cycle turbine, the exhaust must be cooled first. Turbine heat recovery or dilution air systems can reduce exhaust gas temperatures to the proper operating range for the catalyst. An alternative is the use of other catalysts with higher temperature characteristics. The upper range of the temperature window can be increased to a maximum of 590°C using a zeolite catalyst. The hot exhaust from the combustion turbine in a combined-cycle application has an opportunity to cool down in the HSRG and the base metal catalysts are more commonly used for combined-cycle turbines. SCR for combined-cycle turbines are often built into HSRG.

6. Selective Non-catalytic Reduction (SNCR)

SNCR is an add-on technology that involves the noncatalytic decomposition of NO_x in the flue gas to nitrogen and water using reducing agents, such as urea or NH_3. Since SNCR does not require a catalyst, the initial capital costs are lower than SCR. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (e.g., trade name: Thermal DeNOX) requires a reaction temperature window of 870°C to 1,200°C. In the urea process (e.g., trade name: NO_XOUT), the optimum temperature ranges from 870°C to 1,150°C.

7. Water/Steam Injection

Water/steam injection is a mature technology, having been used since the 1970s to control NO_x emissions from gas turbines. Water/steam injection as a control technology involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink, which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NO_x formation. The water used for either approach needs to be demineralized thoroughly to avoid forming deposits and corrosion in the turbine expansion section.

The "water-to-fuel ratio" has a direct impact on the controlled NO_x emission rate and is generally controlled by the turbine inlet temperature and ambient temperature. The decision

[15] California Air Resources Board - BACT Clearinghouse. Web. 15 Apr. 2014. <http://www.arb.ca.gov/bact/bactnew/query.php>.

whether to use water versus steam injection depends on the availability and cost of steam, turbine performance, and maintenance impacts. Direct water impingement can result in rapid wear of the combustor liner. The impact of steam injection has been linked to a reduced life for the hot section parts due to the change in transport properties (added moisture increases heat transfer) and the increased compressor discharge pressure and temperature resulting from the added mass flow.[16]

Wet control technology, which was developed for combustors that had uncontrolled emissions of 100 ppmv or more, can reduce NO_x by 60 percent or more. Both water and steam increase the mass flow through the system and create a small amount of additional power. Wet control typically increases power output by 5 to 6 percent and decreases efficiency up to 4 percent.[17] Controlled NO_x emission levels are generally about 25 ppmv for gas turbines. There are some turbines in which manufacturers indicate an outlet concentration of 15 ppmvd of NO_x when using water/steam injection can be achieved. For example, the GE aeorderivative turbine LM2500 can achieve 15 ppmvd NO_x at 15% O_2 at a steam flow of about 10,000 kg/hr. Also, a CASA member indicated that their 3 aeroderivative GE LM6000 achieved actual emissions less than the 25 ppmvd guarantee.

The expected NO_x emissions from an aeroderivative turbine with no control are 175 ppmv. With steam or water, injection emission levels of 25 ppmv are achievable.

3.2 Eliminate Technically Infeasible Technologies

Certain technologies were rejected from further analysis because the controls are considered technologically infeasible. UDLN and SCR were determined to be feasible technologies. The reason the other technologies are considered infeasible is provided below.

1. DLN with Catalytic Combustion

Catalytic combustion is considered technically infeasible because it is not commercially available for the turbine sizes expected to be installed in Alberta. The only commercially available turbine model with catalytic combustion is the Kawasaki model GPB15X, which has a capacity of 1.4-MW turbine. One source indicated that it was unlikely that catalytic combustion will be used widely on future gas turbines, because the technology has not been demonstrated to perform better than current lean premixed combustors, especially considering the need for an outlet compressor temperature of above 426°C and the limited load settings available at the low NO_x settings.[18]

[16] Hoeft, R.F., Operation and Maintenance of GE Heavy Duty Gas Turbines, GER-3620B.

[17] EPRI. Assessment of Emerging Low-Emissions Technologies for Combustion-Based Distributed Generators, EPRI, Palo Alto, CA: 2005. 1011341.

[18] Modern Gas Turbine Systems-High Efficiency, Low Emission, Fuel Flexible Power Generation, Woodhead Publishing, Cambridge, UK, 2013.

2. NSCR

NSCR is considered technically infeasible because lean-burn DLN combustion is assumed for the turbine combustor design in this analysis. These combustors operate under fuel-lean conditions (relatively high excess oxygen). NSCR requires a low excess oxygen concentration in the exhaust gas stream to be effective.

3. SCONO$_X$™

SCONO$_X$™ is considered technically infeasible because it is not commercially available. Although the technology has been installed and operated on one 45 MW turbine in California, it is not a mature technology. The majority of permitted and operating units are small 5-MW units. There are no known installations in low ambient temperature settings. The SCONO$_X$™ / EM$_X$™ technology cannot be applied with predictable results.

The maximum catalyst operating temperature is 370^{o}C. It should also be noted that the use of the SCONO$_X$™ catalyst for simple-cycle installations might be limited due to temperature. SCONO$_X$™ is also very sensitive to fuels other than natural gas; sulfur in other fuel types might coat or cover the catalyst active sites, reducing NO_x or NH_3 diffusion and necessitating frequent cleaning.

4. SNCR

SNCR is considered technically infeasible because of incompatibility with both the simple- and combined-cycle, turbine exhaust temperature range of 425°C to 540°C. The optimum temperature range for SNCR is between 870°C to 1,150°C. Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbines. It might be feasible to initiate this reaction in the gas turbine (where operating temperatures fall within the reaction window) if suitable modifications and injection systems can be developed; however, this technology has not been applied to date. Aeroderivatives' turbine exhaust temperature, ranging from 370°C to 540°C, is also outside the optimum temperature range for SNCR.

5. Water/Steam Injection

Water/steam injection is considered technically infeasible for this analysis because the baseline control has been chosen as a DLN burner. The majority of commercially available DLN combustors achieve NO_x reduction to 25 ppmv. NO_x guarantees as low at 9 ppmv can be obtained.[19] Water/steam injection can also obtain 25 ppmv levels of NO_x for some turbines, and even lower in some cases. However, wet injection is not expected to reduce NO_x lower than the DLN for most turbines; therefore, water/steam injection is considered technically infeasible for a turbine with a DLN burner installed.

Because water/steam injection can often achieve NO_x outlet concentrations of 25 ppmvd or less, this technology is equivalent to the use of DLN burners in these applications.

[19] EPRI. Design Evolution, Durability and Reliability of General Electric Heavy Duty Combustion Turbines: Pedigree Matrices, Volume 3, EPRI, Palo Alto, CA: 2007. 1012716.

3.3 Rank Control Technologies

As presented in Section 3.2, Ultra DLN and SCR are considered technically feasible for NO_x control. Technical literature shows that an SCR system installed on a simple-cycle, gas-fired turbine can achieve a NO_x concentration of 2.0 ppmv.[20] It is assumed that combined-cycle, gas-fired sources can achieve these same levels of emission reduction. UDLN turbines can achieve down to 4 ppm as shown in Table 3-1. However, there are only 7 out of the 34 UDLN turbine models that achieve a performance of less than 15 ppmv. The majority of UDLN are those that meet a 15 ppmv performance level. Therefore, UDLN turbines are assumed to achieve a NO_x concentration of 15 ppmv. These performance levels result in a control technology ranking of:

1. SCR with exhaust concentration of 2 ppmv.
2. UDLN with exhaust concentration of 15 ppmv.

3.4 Determine Control Costs and Emission Reduction

Section 3.4.1 provides information on the turbines that were used in developing costs and overall assumptions made in developing the costs. Details on developing costs for SCR are in 3.4.2 and a description of the UDLN costs in Section 3.4.3. The methodology for calculating the costs for low NO_x burners used in HRSGs for combine cycle and cogeneration is in Section 3.4.4. The cost results are in Section 3.4.5 and emissions and emission reduction results in Section 3.4.6.

3.4.1 *Control Costs Background*

ERG developed costs for installing SCR and UDLN turbines for 30 different scenarios. In addition, costs were estimated for using low NO_x burners in the HRSG for combined cycle turbines and cogeneration installations. The 30 scenarios varied by turbine size, operating cycle (peaking and base load) and supplemental heat (duct burners). The turbine units were developed to evaluate the control technologies for a range of gas turbine sizes and loads. Each operating scenario and size combination that was considered is shown in Table 3-2. The bases for the model turbine specifications are described in this section.

Size Ranges

ERG has subdivided combustion turbines into four size ranges. These sizes are small-1 (25-75 MW), small-2 (75-150 MW), medium (150-200 MW), and large (greater than 200 MW). Small combustion turbines (less than 25 MW) have been excluded because they are not expected to be used at electric utilities or industrial cogeneration facilities.

These ranges were established based on a review of the DOE EIA database of operating turbines in the United States. ERG developed the size ranges to represent the sizes expected in the future and to provide ranges that were small enough that any member of a group would be well represented by the parameters assigned to that group.

[20] EPRI. Combustion Turbine Experience and Intelligence Report: 2002, Combustion Turbine/Combined Cycle Technology Developments, Reliability Issues, and Related Market Conditions, EPRI, Palo Alto, CA: 2002. 1004640.

Table 3-2. Model Units for New Gas Turbines

Class	Combustion Turbine Power Output Size Range (MW)	Combustion Turbine Power Output Representative Size (MW)	Operating Cycle	Total Facility Gross Power Output (MW)[1]	Load
Small 1	25-75	50	Simple Cycle	50	Peaking
Small 2	75-150	113	Simple Cycle	113	Peaking
Small 1	25-75	50	Simple Cycle	50	Base
Small 2	75-150	113	Simple Cycle	113	Base
Medium	150-200	175	Simple Cycle	174	Base
Large 1	greater than 200	300	Simple Cycle	300	Base
Small 1	25-75	50	Combined Cycle	78	Base
Small 2	75-150	113	Combined Cycle	168	Base
Medium	150-200	175	Combined Cycle	277	Base
Large 1	greater than 200	300	Combined Cycle	467	Base
Small 1	25-75	50	Combined Cycle w/ Duct Burner	90	Base
Small 2	75-150	113	Combined Cycle w/ Duct Burner	191	Base
Medium	150-200	175	Combined Cycle w/ Duct Burner	317	Base
Large	greater than 200	300	Combined Cycle w/ Duct Burner	535	Base
Small 1	25-75	50	Combined Cycle w/ LNB Duct Burner	90	Base
Small 2	75-150	113	Combined Cycle w/ LNB Duct Burner	191	Base
Medium	150-200	175	Combined Cycle w/ LNB Duct Burner	317	Base
Large	greater than 200	300	Combined Cycle w/ LNB Duct Burner	535	Base
Small 1	25-75	50	Cogeneration	50	--
Small 2	75-150	113	Cogeneration	113	--
Medium	150-200	175	Cogeneration	175	--
Large	greater than 200	300	Cogeneration	300	--
Small 1	25-75	50	Cogeneration with Duct Burner	50	--
Small 2	75-150	113	Cogeneration with Duct Burner	113	--
Medium	150-200	175	Cogeneration with Duct Burner	175	--
Large	greater than 200	300	Cogeneration with Duct Burner	300	--
Small 1	25-75	50	Cogeneration with LNB Duct Burner	50	--
Small 2	75-150	113	Cogeneration with LNB Duct Burner	113	--
Medium	150-200	175	Cogeneration with LNB Duct Burner	175	--
Large	greater than 200	300	Cogeneration with LNB Duct Burner	300	--

[1] Total facility power output (MW) includes the power output from the combustion turbine generator and the steam turbine generator for combined cycle turbines. The electricity generated by the steam turbine was estimated based on the anticipated heat recovered from turbine exhaust and any additional heat from duct burners. The facility output for cogeneration systems is based on the electrical generating capacity.

Operating Cycle

In addition to size, ERG included a peaking operating cycle subcategory under the two smaller sized turbines. Peaking units are designed to generate energy on short notice and for relatively short periods of time. Peaking units are used when all other units and energy sources are operating at maximum capability during peak hours or during unforeseen outages. ERG assumed 50 percent utilization for peaking units, or 4,200 hours per year. Although this utilization assumption might be higher than many individual utilities, it allows for a conservative estimation of cost effectiveness (dollar per tonne of NO_x reduction). If a combustion turbine is not operational, no removal occurs, and no return on capital costs investment is realized. ERG assumes a base load unit will operate 8,400 hours per year (24 hrs/day, 7 days/week, 50 weeks/yr).

Basic equipment for an operational combined-cycle package includes gas turbines, Heat Recovery Steam Generator (HRSG), steam turbine, and electric generators. The combined-cycle system incorporates two simple-cycle systems into one generation unit to maximize energy efficiency. Energy is produced in the first cycle using a gas turbine; then the heat that remains is used to create steam, which is run through a steam turbine. With respect to NO_x emissions, the only additional consideration for combined-cycle turbines is the use of a duct burner in the HRSG.

Cogeneration scenarios were also considered in the cost calculations. Cogeneration installations are similar to combined cycle except that the steam generated in the HRSG is used to perform a function at an industrial site and is not used to generate more electricity in a steam turbine. Cogeneration system may or may not have fired duct burners for supplemental heat.

Duct Burners

For combined cycle and most cogeneration configurations, a HRSG is installed following the combustion turbine to recover heat in the turbine exhaust and create steam. The steam is then used for industrial processes in the case of cogeneration installation or sent to a steam turbine to generate more electricity in the case of combined cycle turbines. In some cases the HRSG contains duct burners that burn additional fuel to increase the amount of steam that can be produced. Approximately two-thirds of existing combined-cycle plants use duct burners to increase combined-cycle power output.[21] Model units assume duct burner packages are 25 percent of the combustion turbine heat input capacity for combined cycle systems and 35 percent for cogeneration.

3.4.2 *SCR Control Costs*

The control cost estimation procedures are based on EPA’s Control Cost Manual, 6th Edition (2002).[22]

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[21] EPRI. Combustion Turbine Experience and Intelligence Report: 2002, Combustion Turbine/Combined Cycle Technology Developments, Reliability Issues, and Related Market Conditions, EPRI, Palo Alto, CA: 2002. 1004640.

[22] US EPA - Office of Air Quality Planning And Standards. *EPA Air Pollution Control Cost Manual, Sixth Edition (EPA/452/B-02-001).* Research Triangle Park, NC: 2002. Web. 20 May 2014. <http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf>.

Purchased Equipment Cost

Based on a discussion with a turbine manufacturer, SCR equipment costs were estimated based on $45 per kW for SCR used with single cycle turbines. The costs for SCR used for combined cycle and cogeneration configurations is much lower because the SCR is placed in the HRSG. Therefore, the SCR costs do not include the housing and supports because their costs are associated with the HRSG. ERG assumed the cost of a combined cycle SCR. Basic equipment costs include an NH_3 injection skid, NH_3 storage equipment, and instrumentation. Capital costs include taxes, freight charges, and installation costs. Catalyst costs are based on a DOE cost analysis.[23]

Direct and Indirect Installation Costs

Direct and indirect installation costs are estimated as a percentage of the purchased equipment cost as specified in the Cost Manual.[24] The equations for each line-item cost are presented in Appendix A. Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. SCR will not require buildings, site preparation, offsite facilities, or land.

Indirect installation costs include costs such as construction and field expenses (i.e., costs for construction supervisory personnel, office personnel), startup and performance test costs (to get the control system running and to verify that it meets performance guarantees), and contingencies. Contingencies cover unforeseen costs that may arise, such as modification of equipment, escalation increases in equipment cost, or delays encountered in startup. Project contingency costs are assumed to equal 3 percent of purchased equipment.

Annual Costs

Direct annual costs include the purchase costs of SCR catalysts, reducing reagent (ammonia), electrical power, and labour necessary to maintain good operation. Indirect annual costs include overhead, property taxes, insurance, administrative changes and capital recovery. Total Annual Costs (TAC) are the sum of the direct and indirect annual costs.

The SCR reactor is a stationary device with no moving parts. Further, the SCR system incorporates only a few pieces of rotating equipment (e.g., pumps, motors). It is assumed that the existing plant staff spend 30 minutes per shift to maintain the SCR.[25] The facility operator and maintenance labour rates are obtained from Canadian Labour Relations literature. [26] The SCR catalyst reactor increases the back pressure on the turbine, which decreases the turbine power output by approximately 0.5 percent; this was used to derate power assumed from the

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[23] ONSITE SYCOM Energy Corporation. Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines. Prepared for the U.S. Department of Energy, Contract No. DEFC02-97CHIO877. November 5, 1999.

[24] US EPA - Office Of Air Quality Planning And Standards. *EPA Air Pollution Control Cost Manual, Sixth Edition (EPA/452/B-02-001).* Research Triangle Park, NC: 2002. Web. 20 May 2014. <http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf>.

[25] ONSITE SYCOM Energy Corporation. Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines. Prepared for the U.S. Department of Energy, Contract No. DEFC02-97CHIO877. November 5, 1999.

[26] Construction Labour Relations. *Wage Summary Construction – Alberta 2011-2015. March 12, 2014.* Web. 20 May 2014. <http://www.clra.org/assets/page/files/agreements/Wage%20Summaries/Wage_Summary.pdf>.

combustion turbine. The estimated costs account for the electrical demand of the NH_3 injection blower. The SCR catalyst cost and ammonia reagent usage are based on simple equations.

Catalyst in gas-fired applications are expected to last 7 years.[27] ERG assumed the catalyst life for both base load and peaking units to be 7 years. ERG assumed 50 percent utilization for peaking units, or 4,200 hours per year. Catalyst for peaking units could last longer than base unit catalysts; however the additional life gained is uncertain given the frequent startup and shutdown nature of peaking units and associated thermal stresses.

The life of the SCR system depends on many factors, including operating environment, maintenance practices, and construction materials. To calculate the capital recovery costs, ERG assumed a 20-year expected useful life of the SCR system and a 7 percent discount rate.[28] This assumes no salvage value can be taken for the system at the conclusion of its useful life. Even if it were reusable, the cost of disassembling the system into its components could be as high as the salvage value. The addition of add on control will have no affect on the useful life of a peaking or base load turbine.

3.4.3 *UDLN Control Cost Components*

In order to determine the cost associated with UDLN turbines with respect to the baseline level of control (DLN), the difference in cost between UDLN and DLN must be determined. The 2013 Gas Turbine World Handbook[29] was consulted for combustion turbine costs. Table 3-3 shows turbine costs for several turbine models. The level of NO_x emissions for each model was not specifically identified for the turbines; however, manufacturer websites and brochures were reviewed to determine the level of NO_x expected for each turbine model. Some turbine models could be acquired in different configurations and with different combustors; therefore, it was not always obvious what performance level should be assigned to each model number. Table 3-3 provides the performance levels for each turbine that could be determined or inferred by the vendor websites and brochures.

Comparing the costs in Table 3-3 for DLN and UDLN is difficult because there are several factors that impact the costs, such as manufacturer, type of turbine, electricity frequency, the size, and various configuration details (e.g. enhanced power technology [GE's Sprint and Rolls Royce's ISI], air cooling, steam cooling, etc.).

[27] EPRI, 2003, Recycling and Disposal of Spent Selective Catalytic Reduction Catalyst, 1004888, October 2003.

[28] ONSITE SYCOM Energy Corporation. Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines. Prepared for the U.S. Department of Energy, Contract No. DEFC02- 97CHIO877. November 5, 1999.

[29] 2013 Gas Turbine World Handbook (Volume 30). Pequot Publishing, 2013. Farmer, Robert, ed. http://www.gasturbineworld.com/. Web. August 2014.

Table 3-3. Cost of DLN and UDLN Turbines

Manufacturer	Frequency	Model	MW	Total Cost	$/kW	Controls	NO_x Level
Rolls Royce	50/60	RB211-G62 DLE	27	$10,530,000	$387	DLN	25
GE Energy Aeroderivative	60	LM2500PR	30	$10,850,000	$356	DLN	25
Rolls Royce	50/60	RB211-GT62 DLE	30	$11,380,000	$381	DLN	25
Rolls Royce	50/60	RB211-GT61 DLE	32	$12,190,000	$379	DLN	25
Siemens Energy	50/60	SGT-700	32	$11,950,000	$371	UDLN	15
GE O&G	50/60	PGT25+G4	33	$12,330,000	$373	DLN	25
Siemens Energy	50/60	SGT-750	36	$13,030,000	$363	UDLN	15
GE Energy Aeroderivative	50	LM6000PF	43	$15,340,000	$359	UDLN	15
GE Energy Aeroderivative	60	LM6000PF Sprint	48	$16,280,000	$339	UDLN	15
Siemens Energy	50/60	SGT-800 (option 1)	48	$16,040,000	$338	UDLN	15
Rolls Royce	60	Trent 60 DLE	54	$18,140,000	$336	DLN	25
Rolls Royce	60	Trent 60 DLE ISI	62	$ 19,040,000	$308	DLN	25
GE Heavy Duty	50/60	6F 3-series	78	$22,220,000	$286	UDLN	15
GE Heavy Duty	60	7E 3-series	89	$24,090,000	$272	UDLN	4
GE Energy Aeroderivative	60	LMS100PB	99	$38,400,000	$386	DLN	25
Siemens Energy	60	SGT6-2000E	112	$31,870,000	$285	DLN	25
Alstrom	60	GT11N2	115	$32,200,000	$279	DLN	25
GE Heavy Duty	50	9E 3-series	128	$35,050,000	$273	UDLN	5
Siemens Energy	50	SGT5-2000E	166	$43,070,000	$259	DLN	25
Mitsubishi	60	M501F3	185	$45,350,000	$245	UDLN	15
Alstrom	50	GT13E2	203	$52,590,000	$259	UDLN	15
GE Heavy Duty	60	7F 5-series	216	$51,770,000	$240	UDLN	9
Alstrom	60	GT24	231	$55,140,000	$239	UDLN	15
Siemens Energy	60	SGT6-5000F	232	$49,420,000	$213	UDLN	9
GE Heavy Duty	50	9F 3-series	261	$59,290,000	$227	UDLN	15
Siemens Energy	60	SGT6-8000H	274	$64,980,000	$237	DLN	25
Mitsubishi	60	M501GAC	276	$63,400,000	$230	UDLN	15
Siemens Energy	50	SGT5-4000F	292	$68,160,000	$233	DLN	25
GE Heavy Duty	50	9F 5-series	298	$68,490,000	$230	DLN	25
Alstrom	50	GT26	326	$74,890,000	$230	UDLN	15
Mitsubishi	50	M701G2	334	$75,480,000	$226	UDLN	15
Mitsubishi	50	M701F5	359	$79,790,000	$222	UDLN	15
Siemens Energy	50	SGT5-8000H	375	$85,440,000	$228	DLN	25

3.4.4 *Low NO_x Duct Burner Control Cost*

Information was not located on the cost difference between conventional HRSG duct burners and low NO_x burners (LNB). To estimate the cost of LNB duct burners, ERG used the difference in cost between conventional burners and LNB used in boilers. An EPA report with control costs[30] stated that the additional costs necessary for LNB is $1,500 per burner and a burner is needed for every 10 MMBtu/hr. For example, for 100 MMBtu/hr of supplemental firing, 10 individual burners are needed, each $1,500, or a total of $15,000 in 2000 dollars, or $21,600 in 2013 dollars.

3.4.5 *Control Cost*

Tables 3-4, 3-5, 3-6, and 3-7 provide cost results for control with SCR for single and combined cycle turbines; control with ULNB for single and combined cycle plants; control with SCR for cogeneration installations; and control with ULNB for cogeneration installations; respectively. These tables summarize the estimated NO_x control costs.

The total gross facility power output of a combined-cycle plant includes the steam turbine generator and the combustion turbine generator. The tables also present the total capital costs as a function of the total energy produced over the lifetime of the SCR or UDLN ($/MW-hr). Using this measure the combined cycle SCR is more affordable given that the steam turbine generator does not produce NO_x emissions. Purchased equipment cost, installation costs, and annual costs for each model unit, are included in Appendix A.

Table 3-4. SCR Control Costs

Model Unit Description	Total Facility Net Power Output (MW)[1]	Total Capital Investment (TCI)[2]			Total Annual Costs (TAC)[5]		
		Million $	Lifetime ($/MW-hr)[3]	Cost ($/kW)[4]	Million $/yr	Per energy produced ($/MW-hr)[6]	Per power capacity ($/kW)[7]
50 MW - SC - Peak	50	3.91	0.94	79	0.81	3.89	16
113 MW - SC - Peak	112	8.80	0.94	79	1.68	3.57	15
50 MW - SC - Base	50	3.91	0.47	79	1.01	2.42	20
113 MW - SC - Base	112	8.80	0.47	79	1.97	2.10	18
175 MW - SC - Base	174	13.7	0.47	79	2.93	2.00	17
300 MW - SC - Base	299	23.5	0.47	79	4.85	1.93	16
50 MW - CC - Base	78	1.96	0.15	25	0.75	1.14	10
113 MW - CC - Base	167	4.40	0.16	26	1.38	0.98	8.3
175 MW - CC - Base	276	6.85	0.15	25	2.01	0.87	7.3
300 MW - CC - Base	465	11.7	0.15	25	3.27	0.84	7.0
50 MW - CC - Base w/ DB	89	1.96	0.13	22	0.81	1.07	9.0
113 MW - CC - Base w/ DB	190	4.40	0.14	23	1.50	0.94	7.9
175 MW - CC - Base w/ DB	316	6.85	0.13	22	2.21	0.83	7.0
300 MW - CC - Base w/ DB	532	11.7	0.13	22	3.61	0.81	6.8

[30] U.S. EPA, 2000, Petroleum Refinery Tier 2 BACT Analysis Report, March 14, 2000.

Table 3-4. SCR Control Costs

Model Unit Description	Total Facility Net Power Output (MW)[1]	Total Capital Investment (TCI)[2]			Total Annual Costs (TAC)[5]		
		Million $	Lifetime ($/MW-hr)[3]	Cost ($/kW)[4]	Million $/yr	Per energy produced ($/MW-hr)[6]	Per power capacity ($/kW)[7]
50 MW - CC - Base w/ DB LNB	89	2.0	0.13	22	0.80	1.07	9.0
113 MW - CC - Base w/ DB LNB	190	4.4	0.14	23	1.50	0.94	7.9
175 MW - CC - Base w/ DB LNB	316	6.8	0.13	22	2.20	0.83	7.0
300 MW - CC - Base w/ DB LNB	532	12	0.13	22	3.60	0.80	6.8

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Duct Burners; all dollars are in 2013 US dollars

1 Total facility power output (MW) includes the power output from the combustion turbine generator and the steam turbine generator for combined cycle turbines. The electricity generated by the steam turbine was estimated based on the anticipated heat recovered from the turbine exhaust and any additional heat from duct burners.

2 TCI (Million $US) is the total capital investment associated with the SCR. For scenarios where a LNB is used instead of a conventional duct burner, the TCI also includes the incremental capital investment for the LNB.

3 TCI Lifetime ($/MW-hr) is capital cost of the SCR allocated (and incremental capital cost of LNB, if applicable) to each MW-hr of energy produced over the life time of the equipment. It is equal to TCI divided by the total facility maximum energy output over the 20-year life of the equipment, where peaking units operate 4,200 hours per year, and base load units operate 8,400 hours per year.

4 TCI Cost ($/kW capacity) is the TCI divided by the capacity of the total facility.

5 TAC (Million $/yr) is the amortized TCI (capital recovery) plus the Direct Annual Costs associated with the SCR (and LNB, if applicable).

6 TAC per energy produced ($/MW-hr annual) is the TAC divided by the annual total facility energy output.

7 TAC per power capacity ($/kW) is the TAC divided by the electric generating capacity of the total facility.

Table 3-5. UDLN Control Costs

Model Unit Description	Total Facility Net Power Output (MW)[1]	Total Capital Investment (TCI)[2]			Total Annual Costs (TAC)[5]		
		Million $	Lifetime ($/MW-hr)[3]	Cost (Million $/MW Capacity)[4]	Million $/yr	Per energy produced ($/MW-hr)[6]	Per power capacity (Million $/MW)[7]
50 MW - SC - Peak	50	0.92	0.22	18	0.12	0.59	2.5
113 MW - SC - Peak	113	2.1	0.22	18	0.28	0.59	2.5
50 MW - SC - Base	50	0.92	0.11	18	0.12	0.29	2.5
113 MW - SC - Base	113	2.1	0.11	18	0.28	0.29	2.5
175 MW - SC - Base	175	3.2	0.11	18	0.43	0.29	2.5
300 MW - SC - Base	300	5.5	0.11	18	0.74	0.29	2.5
50 MW - CC - Base	78	0.92	0.070	12	0.12	0.19	1.6
113 MW - CC - Base	168	2.1	0.073	12	0.28	0.20	1.7
175 MW - CC - Base	277	3.2	0.069	12	0.43	0.19	1.6
300 MW - CC - Base	467	5.5	0.070	12	0.74	0.19	1.6
50 MW - CC - Base w/ DB	90	0.92	0.061	10	0.12	0.16	1.4
113 MW - CC - Base w/ DB	191	2.1	0.064	11	0.28	0.17	1.5

Table 3-5. UDLN Control Costs

Model Unit Description	Total Facility Net Power Output (MW)[1]	Total Capital Investment (TCI)[2]			Total Annual Costs (TAC)[5]		
		Million $	Lifetime ($/MW-hr)[3]	Cost (Million $/MW Capacity)[4]	Million $/yr	Per energy produced ($/MW-hr)[6]	Per power capacity (Million $/MW)[7]
175 MW - CC - Base w/ DB	317	3.2	0.060	10	0.43	0.16	1.4
300 MW - CC - Base w/ DB	535	5.5	0.061	10	0.74	0.16	1.4
50 MW - CC - Base w/ DB LNB	90	0.94	0.062	10	0.13	0.17	1.4
113 MW - CC - Base w/ DB LNB	191	2.1	0.066	11	0.29	0.18	1.5
175 MW - CC - Base w/ DB LNB	317	3.3	0.061	10	0.45	0.17	1.4
300 MW - CC - Base w/ DB LNB	535	5.6	0.062	10	0.77	0.17	1.4

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Duct Burners; all dollars are in 2013 US dollars

1 Total facility power output (MW) includes the power output from the combustion turbine generator and the steam turbine generator for combined cycle turbines. The electricity generated by the steam turbine was estimated based on the anticipated heat recovered from the turbine exhaust and any additional heat from duct burners.

2 TCI (Million $US) is the incremental capital investment cost associated with using a UDLN turbine instead of a DLN. For scenarios where a LNB is used instead of a conventional duct burner, the TCI also includes the incremental capital investment for the LNB.

3 TCI Lifetime ($/MW-hr) is the TCI allocated to each MW-hr of energy produced over the life time of the equipment. It is equal to TCI divided by the total facility maximum energy output over the 20-year life of the equipment, where peaking units operate 4,200 hours per year, and base load units operate 8,400 hours per year.

4 TCI Cost ($/kW capacity) is the TCI divided by the capacity of the total facility.

5 TAC (Million $/yr) is the amortized TCI (capital recovery) associated with the UDLN and LNB, if applicable. Direct Annual Costs associated with the UDLN and LNB are assumed zero since these cost would not be greater than the costs for DLN or conventional duct burners.

6 TAC per energy produced ($/MW-hr annual) is the TAC divided by the annual total facility energy output.

7 TAC per power capacity ($/kW) is the TAC divided by the capacity of the total facility.

Table 3-6. SCR CHP Control Costs

Model Unit Description	Total Facility Net Power Output (MW_e)[1]	Total Thermal Energy Output (MW_{th})[2]	Total Capital Investment (TCI)[3] (Million $)	Total Annual Costs (TAC)[4] (Million $/yr)
50 MW - CHP - Base	50	46	2.0	0.75
113 MW - CHP - Base	112	89	4.4	1.4
175 MW - CHP - Base	174	164	6.8	2.0
300 MW - CHP - Base	299	269	12	3.3
50 MW - CHP - Base w/ DB	50	71	2.0	0.83
113 MW - CHP - Base w/ DB	112	141	4.4	1.6
175 MW - CHP - Base w/ DB	174	254	6.8	2.3
300 MW - CHP - Base w/ DB	299	420	12	3.8
50 MW - CHP - Base w/ DB LNB	50	71	2.0	0.83
113 MW - CHP - Base w/ DB LNB	112	141	4.4	1.6
175 MW - CHP - Base w/ DB LNB	174	254	6.8	2.3
300 MW - CHP - Base w/ DB LNB	299	420	12	3.7

CHP = Combined Heat and Power or Cogeneration Systems; DB = Duct Burner; LNB = Low NO_x Duct Burners; all dollars are in 2013 US dollars

[1] Total facility power output (MW) includes the power output from the combustion turbine generator.

[2] Total Thermal Energy Output (MW_{th}) is the heat produced by the cogeneration system for use on an industrial site.

[3] TCI (Million $US) is the total capital investment associated with the SCR. For scenarios where a LNB is used instead of a conventional duct burner, the TCI also includes the incremental capital investment for the LNB.

[4] TAC (Million $/yr) is the amortized TCI (capital recovery) plus the Direct Annual Costs associated with the SCR (and LNB, if applicable).

Table 3-7. UDLN CHP Control Costs

Model Unit Description	Total Facility Net Power Output (MW_e)[1]	Total Thermal Energy Output (MW_{th})[2]	Total Capital Investment (TCI)[3] (Million $)	Total Annual Costs (TAC)[4] (Million $/yr)
50 MW - CHP - Base	50	46	0.92	0.12
113 MW - CHP - Base	113	89	2.1	0.28
175 MW - CHP - Base	175	165	3.2	0.43
300 MW - CHP - Base	300	270	5.5	0.74
50 MW - CHP - Base w/ DB	50	72	0.92	0.12
113 MW - CHP - Base w/ DB	113	142	2.1	0.28
175 MW - CHP - Base w/ DB	175	256	3.2	0.43
300 MW - CHP - Base w/ DB	300	422	5.5	0.74
50 MW - CHP - Base w/ DB LNB	50	72	0.95	0.13
113 MW - CHP - Base w/ DB LNB	113	142	2.1	0.28
175 MW - CHP - Base w/ DB LNB	175	256	3.3	0.44
300 MW - CHP - Base w/ DB LNB	300	422	5.6	0.76

CHP = Combined Heat and Power or Cogeneration Systems; DB = Duct Burner; LNB = Low NO_x Duct Burners; all dollars are in 2013 US dollars

[1] Total facility power output (MW) includes the power output from the combustion turbine generator.

[2] Total Thermal Energy Output (MW_{th}) is the heat produced by the cogeneration system for use on an industrial site.

[3] TCI (Million $US) is the incremental capital investment associated with using a UDLN turbine instead of a DLN. For scenarios where a LNB is used instead of a conventional duct burner, the TCI also includes the incremental capital investment for the LNB.

[4] TAC (Million $/yr) is the amortized TCI (capital recovery) associated with the UDLN and LNB, if applicable. Direct Annual Costs associated with the UDLN and LNB are assumed zero since these cost would not be greater than the costs for DLN or conventional duct burners.

3.4.6 *Estimation of Emission Reductions*

To calculate emission reductions due to applying an emissions control, the baseline emissions and emissions after controls were calculated, along with the difference between these two values, which are the emissions reductions. Baseline emissions are generally those emissions that would occur if the control technology is not applied. Baseline emissions for each turbine scenario were calculated. The baseline for the combustion turbine was calculated based on the assumed 25 ppmv baseline emissions rate for each turbine with DLN. Baseline for fired duct burners was calculated assuming an emission rate of 82 g/GJ as specified in AP-42[31] for uncontrolled boilers. The baseline emissions only vary due to the size of the turbine and for combined cycle and cogeneration installations that have duct burners. The baseline emissions are independent of the controls that are applied and are shown in Table 3-8 for each scenario. Combined cycle and cogeneration (CHP) scenarios are grouped together because they have the same baseline, as well as baseline duct burners and LNB duct burner scenarios.

Table 3-8. Baseline NO_x Emissions

Total Facility Gross Power Output (MW)[1]	Model Unit Description	Baseline NO_x from Turbine (tonnes/yr)	Baseline NO_x from Duct Burners (tonne/yr)	Total Baseline NO_x (tonne/yr)
50	50 MW - SC - Peak	91.9		91.9
113	113 MW - SC - Peak	207		207
50	50 MW - SC - Base	184		184
113	113 MW - SC - Base	414		414
174	175 MW - SC - Base	643		643
300	300 MW - SC - Base	1,103		1,103
78	50 MW - CC or CHP	184		184
168	113 MW - CC or CHP	414		414
277	175 MW - CC or CHP	643		643
467	300 MW - CC or CHP	1,103		1,103
90	50 MW - CC or CHP w/ DB (baseline or LNB)	184	82.3	266
191	113 MW - CC or CHP w/ DB (baseline or LNB)	414	170	583
317	175 MW - CC or CHP w/ DB (baseline or LNB)	643	292	936
535	300 MW - CC or CHP w/ DB (baseline or LNB)	1,103	488	1,591

To calculate the emissions after controls are applied, the expected performance of the control equipment is used. SCR systems, as discussed previously, are generally capable of

[31] US EPA – Office of Air Quality Planning and Standards. Compilation of Air Pollutant Emission Factors AP-42, Section 1.4 External Combustion Sources - Natural Gas Combustion - Supplement D, July 1998.

efficiencies of 80 to 95 percent and NO_x concentrations of 2.0 ppmv[32] are typical to achieve. (A concentration of 2.0 ppmv is also a common emission limit in U.S. permits; this will be discussed further in Section 7.0.) An SCR can be designed to achieve a targeted NO_x reduction by manipulating the reagent usage with respect to the stoichiometric ratio or increasing catalyst volume and the exhaust gas residence time. To achieve a NO_x concentration of 2.0 ppmv, from a 25 ppmv baseline, the necessary SCR removal efficiency is 92 percent.

The emissions from using a UDLN were calculated based on a performance level of 15 ppmv. The concentration was converted to an emissions rate using a fuel factor (F factor) for natural gas and the size of the turbine, as shown in an EPRI document.[33]

Duct burners contribute additional NO_x emissions for combined-cycle and cogeneration turbines. For the emissions when an UDLN is applied to the scenarios for combined-cycle and cogeneration turbines with conventional duct burners, the emissions from the duct burner are equal to the baseline emissions from the duct burner; the total emissions from these scenarios are the emissions from the UDLN plus the baseline emissions from the duct burner. For the scenarios for combined-cycle and cogeneration turbines with LNB duct burners and UDLN turbines, the NO_x emissions from the LNB were calculated assuming an emission rate of 34 g/GJ. This rate was cited as an achievable emission rate for LNB in an EPA report.[34] The total emissions from these scenarios are the emissions from the UDLN plus the emissions from the LNB duct burner.

Because the SCR is typically located downstream of the duct burner, the SCR controls emissions from both the duct burner and combustion turbine. For those scenarios when a SCR is applied to the scenarios for combined-cycle and cogeneration turbines with duct burners, the emissions from the turbine and duct burners are both reduced by the SCR. For conventional duct burners, the emissions to the atmosphere, when an SCR is installed, are the baseline duct burner emissions reduced by the emission reduction efficiency of the SCR of 92%. For the LNB duct burners when an SCR is installed, the emissions were calculated using the 34 g/GJ emission rate and applying the SCR efficiency of 92%.

Subtracting the total emissions for a specific scenario-control combination from the baseline emissions for the scenario gives the emission reductions for the scenario-control combination.

Tables 3-9 through 3-12 show the NO_x emission reductions and emissions for control with SCR and UDLN for each of the scenarios.

Additional emissions associated with startup, shutdown, and malfunction were not estimated but they are discussed in Section 6.1. At lower loads, turbines emit higher levels of NO_x this is discussed in more detail in Section 6.2.

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[32] EPRI. Combustion Turbine Experience and Intelligence Report: 2002, Combustion Turbine/Combined Cycle Technology Developments, Reliability Issues, and Related Market Conditions, EPRI, Palo Alto, CA: 2002. 1004640.

[33] EPRI. Assessment of Emerging Low-Emissions Technologies for Combustion-Based Distributed Generators, EPRI, Palo Alto, CA: 2005. 1011341.

[34] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

Table 3-9. NO_x Emissions and Emission Reductions for Turbines controlled with SCR

Model Unit Description	Total Facility Net Power Output (MW)	Total Baseline Emissions (tonne/yr)	Emissions Reduced by SCR (tonne/yr)	Emissions Reduced by LNB (tonne/yr)	Emissions (tonne/yr)
50 MW - SC - Peak	50	92	84.6		7.35
113 MW - SC - Peak	112	207	190		16.5
50 MW - SC - Base	50	184	169		14.7
113 MW - SC - Base	112	414	381		33.1
175 MW - SC - Base	174	643	592		51.5
300 MW - SC - Base	299	1,103	1,015		88.3
50 MW - CC - Base	78	184	169		14.7
113 MW - CC - Base	167	414	381		33.1
175 MW - CC - Base	276	643	592		51.5
300 MW - CC - Base	465	1,103	1,015		88.3
50 MW - CC - Base w/ DB	89	266	245		21.3
113 MW - CC - Base w/ DB	190	583	537		46.7
175 MW - CC - Base w/ DB	316	936	861		74.9
300 MW - CC - Base w/ DB	532	1,591	1,464		127
50 MW - CC - Base w/ DB LNB	89	266	201	48	17.5
113 MW - CC - Base w/ DB LNB	190	583	446	98	38.8
175 MW - CC - Base w/ DB LNB	316	936	705	169	61.3
300 MW - CC - Base w/ DB LNB	532	1,591	1,204	282	105

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

Table 3-10. NO_x Emissions and Emission Reductions for UDLN Turbines

Model Unit Description	Total Baseline Emissions (tonne/yr)	Emissions Reduced by UDLN (tonne/yr)	Emissions Reduced by LNB (tonne/yr)	Emissions (tonne/yr)
50 MW - SC - Peak	92	36.8		55.2
113 MW - SC - Peak	207	83		124
50 MW - SC - Base	184	74		110
113 MW - SC - Base	414	165		248
175 MW - SC - Base	643	257		386
300 MW - SC - Base	1,103	441		662
50 MW - CC - Base	184	74		110
113 MW - CC - Base	414	165		248
175 MW - CC - Base	643	257		386
300 MW - CC - Base	1,103	441		662
50 MW - CC - Base w/ DB	266	74		193
113 MW - CC - Base w/ DB	583	165		418
175 MW - CC - Base w/ DB	936	257		678
300 MW - CC - Base w/ DB	1,591	441		1,150
50 MW - CC - Base w/ DB LNB	266	74	48	145
113 MW - CC - Base w/ DB LNB	583	165	98	320
175 MW - CC - Base w/ DB LNB	936	257	169	509
300 MW - CC - Base w/ DB LNB	1,591	441	282	867

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

Table 3-11. NO_x Emissions and Emission Reductions for Cogeneration Installations Controlled by SCR

Model Unit Description	Total Facility Net Power Output (MWe)	Total Facility Net Heat Output (MWth)	Total Baseline Emissions (tonne/yr)	Emissions Reduced by SCR (tonne/yr)	Emissions Reduced by LNB (tonne/yr)	Emissions (tonne/yr)
50 MW – CHP	50	46	184	169		14.7
113 MW – CHP	112	89	414	381		33.1
175 MW - CHP	174	164	643	592		51.5
300 MW - CHP	299	269	1,103	1,015		88.3
50 MW - CHP w/ DB	50	71	299	275		23.9
113 MW - CHP w/ DB	112	141	651	599		52.1
175 MW - CHP w/ DB	174	254	1,053	968		84.2
300 MW - CHP w/ DB	299	420	1,786	1,643		143
50 MW - CHP w/ DB LNB	50	71	299	214	67	18.6
113 MW - CHP w/ DB LNB	112	141	651	473	137	41.1
175 MW - CHP w/ DB LNB	174	254	1,053	750	237	65.3
300 MW - CHP w/ DB LNB	299	420	1,786	1,279	395	111

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

Table 3-12. NO_x Emissions and Emission Reductions for Cogeneration Installations with UDLN Turbines

Model Unit Description	Total Facility Net Power Output (MWe)	Total Facility Net Heat Output (MWth)	Total Baseline Emissions (tonne/yr)	Emissions Reduced by UDLN (tonne/yr)	Emissions Reduced by LNB (tonne/yr)	Emissions (tonne/yr)
50 MW – CHP	50	46	184	74		110
113 MW – CHP	112	89	414	165		248
175 MW - CHP	174	165	643	257		386
300 MW - CHP	299	270	1,103	441		662
50 MW - CHP w/ DB	50	72	299	74		159
113 MW - CHP w/ DB	112	142	651	165		348
175 MW - CHP w/ DB	174	256	1,053	257		558
300 MW - CHP w/ DB	299	422	1,786	441		949
50 MW - CHP w/ DB LNB	50	72	299	74	67	226
113 MW - CHP w/ DB LNB	112	142	651	165	137	486
175 MW - CHP w/ DB LNB	174	256	1,053	257	237	795
300 MW - CHP w/ DB LNB	299	422	1,786	441	395	1,345

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

Emissions of PM and ammonia were also calculated for all scenarios. These are shown in Tables 3-13 through 3-16. In determining these emissions, the following assumptions were made:

- All ammonia emissions are produced by the SCR.
- PM emissions from DLN and UDLN turbines are not significantly different.
- PM emissions from conventional duct burners and LNB duct burners are not significantly different.
- PM emissions from turbines are 0.0058 lb/MMBtu or 2.5 g/GJ. This emission factor was calculated based on emissions of 36 tons/year of PM from a 170 MW gas turbine.[35]
- PM emissions from turbines emitted through an SCR are 0.0067 lb/MMBtu or 2.9 g/GJ. This emission factor was calculated based on emissions of 41.6 tons/year of PM from a 170 MW gas turbine controlled by an SCR.[36]

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[35] Schorr, Marvin and Joel Chalfin, Gas Turbine NOx Emisssions Approaching Zero – Is it Worth the Price? http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4172.pdf

[36] Schorr, Marvin and Joel Chalfin, Gas Turbine NO_x Emissions Approaching Zero – Is it Worth the Price? http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4172.pdf

- PM emissions from duct burners are 0.0075 lb/MMBtu[37] or 3.2 g/GJ.
- PM emissions from duct burners exhausted through an SCR are 0.0087 lb/MMBtu or 3.7 g/GJ. This emission factor was calculated assuming that duct burner PM emissions increase by the same proportion as turbine emissions increase (i.e. 0.0067/0.0058).
- The ammonia emissions are 5 ppmvd from the SCR.

Table 3-13. PM and Ammonia Emissions from Turbines controlled with SCR

Model Unit Description	Ammonia Emissions (tonnes/yr)	Ammonia Emissions (kg/hr)	PM Emissions from SCR (tonnes/yr)	PM Emissions from Duct Burner (tonnes/yr)	Total PM Emissions (tonnes/yr)	Total PM Emissions (kg/hr)
50 MW - SC - Peak	1.7	0.40	5.8		5.8	1.4
113 MW - SC - Peak	3.5	0.83	12		12	2.9
50 MW - SC - Base	3.4	0.40	12		12	1.4
113 MW - SC - Base	7.0	0.83	24		24	2.9
175 MW - SC - Base	12	1.4	41		41	4.9
300 MW - SC - Base	20	2.4	69		69	8.2
50 MW - CC - Base	3.4	0.40	12		12	1.4
113 MW - CC - Base	7.0	0.83	24		24	2.9
175 MW - CC - Base	12	1.4	41		41	4.9
300 MW - CC - Base	20	2.4	69		69	8.2
50 MW - CC - Base w/ DB	4.2	0.50	12	19	30	3.6
113 MW - CC - Base w/ DB	8.7	1.0	24	39	63	7.5
175 MW - CC - Base w/ DB	15	1.8	41	67	110	13
300 MW - CC - Base w/ DB	25	3.0	69	112	180	22
50 MW - CC - Base w/ DB LNB	4.2	0.50	12	19	30	3.6
113 MW - CC - Base w/ DB LNB	8.7	1.0	24	39	63	7.5
175 MW - CC - Base w/ DB LNB	15	1.8	41	67	110	13

[37] US EPA – Office of Air Quality Planning and Standards. Compilation of Air Pollutant Emission Factors AP-42, Section 1.4 External Combustion Sources - Natural Gas Combustion - Supplement D, July 1998.

Table 3-13. PM and Ammonia Emissions from Turbines controlled with SCR

Model Unit Description	Ammonia Emissions (tonnes/yr)	Ammonia Emissions (kg/hr)	PM Emissions from SCR (tonnes/yr)	PM Emissions from Duct Burner (tonnes/yr)	Total PM Emissions (tonnes/yr)	Total PM Emissions (kg/hr)
300 MW - CC - Base w/ DB LNB	25	3.0	69	112	180	22

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

Table 3-14. NO_x Emissions and Emission Reductions for UDLN Turbines

Model Unit Description	PM Emissions from UDLN (tonnes/yr)	PM Emissions from Duct Burner (tonnes/yr)	Total PM Emissions (tonnes/yr)	Total PM Emissions (kg/hr)
50 MW - SC - Peak	5.0		5.0	1.2
113 MW - SC - Peak	10		10	2.5
50 MW - SC - Base	10		10	1.2
113 MW - SC - Base	21		21	2.5
175 MW - SC - Base	36		36	4.2
300 MW - SC - Base	60		60	7.1
50 MW - CC - Base	10		10	1.2
113 MW - CC - Base	21		21	2.5
175 MW - CC - Base	36		36	4.2
300 MW - CC - Base	60		60	7.1
50 MW - CC - Base w/ DB	10	16	26	3.1
113 MW - CC - Base w/ DB	21	33	54	6.5
175 MW - CC - Base w/ DB	36	58	93	11
300 MW - CC - Base w/ DB	60	96	156	18
50 MW - CC - Base w/ DB LNB	10	16	26	3.1
113 MW - CC - Base w/ DB LNB	21	33	54	6.5
175 MW - CC - Base w/ DB LNB	36	58	93	11
300 MW - CC - Base w/ DB LNB	60	96	156	18

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

Table 3-15. PM and Ammonia Emissions from Cogeneration Installations Controlled by SCR

Model Unit Description	Ammonia Emissions (tonnes/yr)	Ammonia Emissions (kg/hr)	PM Emissions from SCR (tonnes/yr)	PM Emissions from Duct Burner (tonnes/yr)	Total PM Emissions (tonnes/yr)	Total PM Emissions (kg/hr)
50 MW – CHP	3.4	0.40	12		12	1.4
113 MW – CHP	7.0	0.83	24		24	2.9
175 MW - CHP	12	1.4	41		41	4.9
300 MW - CHP	20	2.4	69		69	8.2
50 MW - CHP - w/ DB	4.6	0.54	12	20	32	3.8
113 MW - CHP - w/ DB	9.4	1.1	24	42	66	7.8
175 MW - CHP - w/ DB	16	1.9	41	72	113	14
300 MW - CHP - w/ DB	27	3.2	69	121	189	23
50 MW - CHP - w/ DB LNB	4.6	0.54	12	20	32	3.8
113 MW - CHP - w/ DB LNB	9.4	1.1	24	42	66	7.8
175 MW - CHP - w/ DB LNB	16	1.9	41	72	113	14
300 MW - CHP - w/ DB LNB	27	3.2	69	121	189	23

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

Table 3-16. NO_x Emissions and Emission Reductions for Cogeneration Installations with UDLN Turbines

Model Unit Description	PM Emissions from SCR (tonnes/yr)	PM Emissions from Duct Burner (tonnes/yr)	Total PM Emissions (tonnes/yr)	Total PM Emissions (kg/hr)
50 MW – CHP	10		10	1.2
113 MW – CHP	21		21	2.5
175 MW - CHP	36		36	4.2
300 MW - CHP	60		60	7.1
50 MW - CHP w/ DB	10	18	28	3.3
113 MW - CHP w/ DB	21	36	57	6.8
175 MW - CHP w/ DB	36	62	98	12
300 MW - CHP w/ DB	60	104	164	19
50 MW - CHP - w/ DB LNB	10	18	28	3.3
113 MW - CHP - w/ DB LNB	21	36	57	6.8
175 MW - CHP - w/ DB LNB	36	62	98	12
300 MW - CHP - w/ DB LNB	60	104	164	19

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

3.5 Assess Environmental and Safety Concerns

There are no additional environmental or safety concerns associated with UDLN turbines or LNB duct burners that are not shared with DLN turbines or conventional duct burners. There are multiple environmental impacts from the use of SCR technology including emission of NH_3, generation of catalyst waste, and use of electricity to operate the SCR. Additional emissions of NH_3 and PM are shown in section 3.4.6.

In the SCR process, aqueous or anhydrous NH_3 is used as the reducing agent and is injected into the flue gas upstream of the catalyst bed. The more NH_3 that is used the more NO_x is removed; therefore, the NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Generally, the more NH_3 used the more likely unreacted NH_3 will "slip" through the process into the atmosphere. Based on a sample of turbine permits, the NH_3 slip emission levels associated with the operation of the SCR are typically limited to less than 5 or 10 ppmvd.

At the end of the catalyst life, it must be trucked offsite for disposal. This occurs every 7 years or so and about 0.9 tonnes are generated per MW.[38] The catalyst can be recycled to recover the Vanadium and other metals in the catalyst.

Electricity is required to operate the SCR. Pumps and fans inject the reducing agent into the flue gas upstream of the catalyst bed. The SCR catalyst reactor increases the back-pressure on the turbine, which requires about 0.5 percent of the turbine power output to overcome.

Assuming that the power use by the SCR is compensated for by combusting more fuel in a comparable natural gas fired combustion turbine, the greenhouse gas emissions from the additional burned fuel were calculated. Table 3-17 shows the required electricity and the resulting greenhouse gas emissions.

Table 3-17. SCR Required Energy and Global Warming Impact

Model	Model Unit Description	Required Electricity (MWh-yr)	Required Additional Fuel (GJ-yr)	CO_2 (tonne/yr)	CH_4 (tonne/yr)	N_2O (tonne/yr)	CO_2e [1] (tonne/yr)
1	50 MW - Peak	1,092	10,474	527	0.00	0.01	530
2	113 MW - Peak	2,426	21,314	1,072	0.00	0.02	1,078
3	50 MW - Base	2,184	20,948	1,054	0.00	0.02	1,060
4	113 MW - Base	4,851	42,629	2,144	0.00	0.04	2,157
5	175 MW - Base	7,518	73,148	3,680	0.01	0.07	3,700
6	300 MW - Base	12,810	121,358	6,105	0.01	0.12	6,139

[1] 100-year Global Warming Potentials (GWP) from U.S. EPA - Greenhouse Gas Reporting Program - Table A-1

Like any chemical process, an SCR poses some safety concerns that generally effect most chemical processes. The owner should limit personnel exposure to elevated pressures and temperatures though isolation or barricading and install both active (e.g., alarms) and passive safeguards (e.g., relief devices, dikes). Operating procedures should be maintained and followed for startup, shutdown, response to upsets, and emergencies.

Ammonia can be supplied in any of three different forms: aqueous, anhydrous, or urea. EPA considers aqueous and anhydrous NH_3 to be hazardous material. Cold temperatures and

[38] EPRI 2003, Recycling and Disposal of Spent Selective Catalytic Reduction Catalyst.

concern for sensitive habitats complicate transportation, storage, and handling of NH_3. Larger SCR systems use anhydrous NH_3, requiring onsite storage of this chemical under pressure. It should be noted that many peaking turbines are located at unattended facilities. The need to store NH_3 at a site that might be unattended for substantial periods of time should be considered. Although anhydrous ammonia is less expensive, aqueous is often specified due to permitting and safety considerations in transport, storage and handling.[39]

3.6 Evaluate Co-benefits

For SCR that control NO_x from coal-fired boilers, there are significant co-benefits in oxidation of vapor phase mercury from the SCR catalyst and then removal of the oxidized mercury in the flue gas desulfurization unit. [40] With no mercury in gas turbine exhaust, an SCR does not offer this same benefit. There are no known co-benefits for SCR on gas turbine exhaust.

[39] EPRI. Reagent Storage and Handling for SCR and SNCR Systems, EPRI, Palo Alto, CA: 2002. 1004148.
[40] Pritchard, Scott, 2009, Predictable SCR Co-benefits for Mercury Control, Power Engineering.

4.0 COMBINED CYCLE AND COGENERATION CONSIDERATIONS

Turbines in combined cycle and cogeneration operations incorporate a HRSG to capture waste heat from the turbine's exhaust gas to generate steam. The temperature of a turbine's exhaust gas is quite hot, 400°C to 500°C for smaller industrial turbines and up to 600ºC for larger turbines, and significant amount of steam can be generated. In combined cycle installations, the generated steam is used in a steam turbine generator to produce additional power. In cogeneration configurations the generated steam is used for industrial processes instead of used to generate power.

4.1 Combined Cycle

The addition of a HRSG to the outlet of the combustion turbine, creates some back pressure that must be overcome with energy produced by the turbine, but the additional energy realized from the generated steam, more than makes up for this loss. The energy output from the steam turbine is about a third of the overall power plant output, with the combustion turbine generating about two thirds of the energy.[41] Capturing this waste heat can boost overall plant efficiency from the range of 40 percent (LHV) for simple cycle plants to about 60 percent (LHV) in combined cycle mode.[42]

It is common to use supplemental firing to increase steam generation. Since very little of the available oxygen in the turbine air flow is used in the combustion process, the oxygen content in the gas turbine exhaust permits supplementary fuel firing ahead of the HRSG to increase steam production relative to an unfired unit. Equipment used to provide supplemental firing is often located in the duct between the combustion turbine exhaust diffuser and the HRSG inlet. These supplemental firing systems are often referred to as duct burners. Supplementary firing can raise the exhaust gas temperature entering the HRSG up to 980°C and increase the amount of steam produced by the unit by a factor of two.[43] Moreover, since the turbine exhaust gas is essentially preheated combustion air, the fuel consumed in supplementary firing is less than that required for a stand-alone boiler providing the same increment in steam generation. The HHV efficiency of incremental steam production from supplementary firing above that of an unfired HRSG is often 85 percent or more when firing natural gas.

Supplementary firing also increases system flexibility. Unfired HRSGs are typically convective heat exchangers that respond solely to exhaust conditions of the gas turbine and do not easily allow for steam flow control. Supplementary firing capability provides the ability to control steam production, within the capability of the burner system, independent of the normal gas turbine operating mode. Duct burners can also burn several kinds of gaseous and liquid fuels and can be designed to support single- or dual-fuel capabilities.

[41] Ragland, A. and W. Stenzel, 2000, Combined Cycle Heat Recovery Optimization, Proceedings of 2000 International Joint Power Generation Conference Miami Beach, Florida.

[42] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

[43] Ragland, A. and W. Stenzel, 2000, Combined Cycle Heat Recovery Optimization, Proceedings of 2000 International Joint Power Generation Conference Miami Beach, Florida.

Approximately two-thirds of existing combined-cycle power plants use duct burners to increase combined-cycle power output.[44] Duct burner manufacturers have demonstrated that NO_x, CO, and unburned hydrocarbon production can be minimized for most applications with a duct burner design that produces certain gas flow dynamics. Low NO_x duct burners with guaranteed emissions levels as low as 34 g/GJ can be specified to minimize the NO_x contribution of supplemental firing.[45] The ppmv level depends on the flowrate of gas turbine exhaust gases at which the burner is operating and thus, varies with the size of the turbine.[46]

For combined cycle systems that use SCR, the SCR catalyst is typically located inside the HSRG behind the high-pressure evaporator on the stack side, downstream of the duct burner. With the SCR placed in this location, conventional catalysts can be used which are less expensive than high or low temperature catalysts.[47] HRSG performance must be evaluated at various modes of operation to ensure that the gas temperatures are within limits set by the catalyst supplier. For most combined-cycle applications, a conventional temperature catalyst type (e.g., vanadium/titanium catalyst on high-density honeycomb structure) with an operating temperature range between 260° and 426°C is used.[48]

4.2 Cogeneration

A gas turbine is operating in cogeneration or combined heat and power (CHP) mode when the waste heat from the turbine exhaust is captured and used directly or used to make steam or hot water. For example, a simple-cycle turbine using the exhaust directly in a dryer is a cogeneration system. A turbine using the exhaust to produce steam in an HRSG is also a cogeneration system if the steam is used in a process (as opposed to a combined cycle power plant where steam from the HRSG is used to produce additional electricity). If the steam is used in a steam turbine to produce additional electricity, it is a combined cycle system and not cogeneration. There are, also installations described as combined cycle cogeneration in which an HRSG produces steam for use in both an end use application and a steam turbine for additional power.

Gas turbines are ideally suited for cogeneration applications because their high-temperature exhaust can be used to generate process steam at conditions as high as 1,200 pounds per square inch gauge (psig) and 480°C or used directly in industrial processes for heating or drying. A typical industrial cogeneration application for gas turbines is a chemicals plant with a 25 MW simple cycle gas turbine supplying base-load power to the plant with an unfired HRSG

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[44] EPRI. Combustion Turbine Experience and Intelligence Report: 2002, Combustion Turbine/Combined Cycle Technology Developments, Reliability Issues, and Related Market Conditions, EPRI, Palo Alto, CA: 2002. 1004640

[45] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

[46] U.S. EPA, Office of Air Quality Planning and Standards, Alternative Control Techniques (ACT) Document - NO_x Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993.

[47] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

[48] EPRI. Combustion Turbine Experience and Intelligence Report: 2002, Combustion Turbine/Combined Cycle Technology Developments, Reliability Issues, and Related Market Conditions, EPRI, Palo Alto, CA: 2002. 1004640.

on the exhaust. Approximately 29 MW thermal (MWth) of steam is produced for process use within the plant.[49]

Gas turbine cogeneration systems can, however, come in a wide range of sizes from very small (<1 MW) to very large (>100 MW). Smaller turbines are generally less efficient in terms of electricity generation than larger units. Conversely, smaller units produce more heat relative to their electrical output that can be captured for beneficial use in a cogeneration system. Depending on the demands of the facility being served, a small cogeneration system may be designed and operated to produce as much as 60 percent of its energy output as thermal energy.

The design and operation of a gas turbine system is largely dependent on the application it serves. Utilities that have no use for thermal energy typically operate in combined cycle mode to maximize electricity output. Industrial or commercial users that have a need for thermal energy will often design a cogeneration gas turbine system around their base electrical or thermal load. Excess electricity may be sold to the local utility when production outstrips demand. Conversely, duct burners offer flexibility for the system to produce additional heat when called for. Cogeneration systems are often able to reach overall system efficiencies (accounting for electricity and useful thermal energy) of 70 to 80 percent.[50]

In terms of emission controls, gas turbine cogeneration systems are effectively no different than gas turbine power plants. As discussed in Section 3, a variety of emission control technologies are available and each must be designed and installed according to how the system operates in order to function properly. SCR systems are very temperature sensitive and must be designed according to system configuration (e.g., systems with (fired) or without (unfired) duct burners).

4.3 Duct Burner Advances

When a gas turbine is equipped with an HRSG, it is common to use supplemental firing to increase steam generation. Equipment used to provide supplemental firing is often located in the duct between the combustion turbine exhaust diffuser and the HRSG inlet. These supplemental firing systems are capable of burning gaseous fuel and are often referred to as duct burners.

Historically, duct burners have been viewed as simple devices that can deliver the increased unit output and operating flexibility with relatively low capital investment, low maintenance costs and a nominal level of operations skill.[51] Duct burner manufacturers have focused on increasing efficiency, lowering emissions, and increasing flexible operations.

More efficient duct burners require turbine exhaust gas and fuel gas flow evenly distributed across the burner array. For uniform fuel gas flow, it is necessary to install fuel balance valves and adjust each valve and orifice to compensate for differences in exhaust gas flow. It is often necessary to install flow straightening devices upstream of, or within, the duct

[49] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf
[50] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf
[51] EPRI. Evaluating and Avoiding Heat Recovery Steam Generator Tube Damage Caused by Duct Burners. EPRI, Palo Alto, CA: 2007. 1012758.

burner array.[52] Computational Fluid Dynamics (CFD) is a common tool for optimizing fluid flows and heat transfer.[53]

Duct burner vendors use staged combustion and premixed fuel and turbine exhaust to achieve low NO_x emissions; these burners are referred to as low NO_x duct burners.[54,55] Zeeco divides the duct burner array into sections to adjust flow conditions since NO_x production may increase with an increase in temperature and CO, particulate, and volatile organic compounds (VOC) may increase with a decrease in temperature.[56] Low NO_x duct burners can guarantee emissions levels as low as 34 g/GJ,[57] with conventional duct burners, emissions are about 82 g/GJ for a large unit while emissions from smaller unit are 43 g/GJ.[58] According to a review of about 25 recent construction permits for combined cycle turbines with duct burners in the HRSG, the use of low NO_x duct burners is not common; no low NO_x burners were identified in these permits.

Alstrom, NEM USA, and Nooter Eriksen are all developing new designs to decrease startup time and to address increased cycling times. For example, NEM USA's Drum Plus HRSG can startup in 10 minutes with no degradation.[59]

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52 Ibid.

53 Giuliano, Cammarata, Caggia Salvatore, Anastasi Massimo, and Petrone Giuseppe. Reacting Flows in Post-Combustion Burners of a Heat Recovery Steam Generator. The Netherlands: 5th European Thermal-Sciences Conference, 2008. Web. 20 May 2014. <http://www.eurotherm2008.tue.nl/Proceedings_Eurotherm2008/papers/Combustion/COM_9.pdf>.

54 Natcom Burner Solutions (CB-8494). Quebec, Canada: Cleaver-Brooks, 2013. Web. 20 May 2014. <http://www.cleaver-brooks.com/Products-and-Solutions/Burners/Industrial-Burners/NATCOM-Duct-Burner/C-B-NATCOM-Brochure.aspx>.

55 *COEN - Power Plus 2000.* Burlingame, CA: Web. 20 May 2014. <http://inproheat.com/sites/files/documents/powplusm.pdf>.

56 DB Series - Low NO_x Duct Burners. Broken Arrow, OK: Zeeco Burner Division, Web. 20 May 2014. <http://www.zeeco.com/pdfs/Burner_Division_DB%20Series.pdf>.

57 Energy and Environmental Analysis (and ICF International Company). Technology Characterization: Gas Turbines [prepared for Environmental Protection Agency - Climate Protection Partnership Division]. 2008. Web. 20 May 2014. <http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf>.

58 US EPA – Office of Air Quality Planning and Standards. Compilation of Air Pollutant Emission Factors AP-42, Section 1.4 External Combustion Sources - Natural Gas Combustion - Supplement D, July 1998.

59 Overton, Thomas W., 2014, Recent Innovations from Gas Turbine and HRSG OEMs, Power Magazine, Vol. 158, No. 6, June 2014.

5.0 SO_2 Emissions from Single and Combined Cycle Turbines

SO_2 emissions from natural gas combustion are generally considered insignificant especially for units burning “pipeline quality natural gas”.[60] However, turbine operators may have other gases available that they would like to use as fuels, such as refinery gas, wood gas, landfill gas, coke oven gas, syngas, etc. Depending on the source, these gases could have much higher quantities of sulfur than pipeline quality gas.

When selecting the gas to burn in a turbine, a turbine operator must consider the effect of having sulfur in the fuel, on the turbine and associated equipment in addition to the resulting emissions of SO_2. Sulfur content in the fuel can cause corrosion in the turbine and/or the HSRG, depending on the combination of several factors including sulfur content, moisture in the gas, gas temperature, and availability of alkali metals such as sodium and potassium.[61] There are several mechanisms that can cause corrosion or fouling. The primary concern for turbines is the formation of sodium or potassium sulfate, which can form at high temperatures 650°C to 800°C and condense out of the exhaust and corrode the metal.[62] At lower temperatures 150°C, which is a greater concern for HSRGs, acid gas can form and condense on to metal surfaces, corroding the metal. The formation of alkali sulfates can happen at low levels of sulfur. An EPA document[63] suggests that levels of total alkalis be kept less than 10 ppm and sulfur content less than single-digit ppm to avoid corrosion from alkali sulfates. This document also recommends that the minimum stack temperature in the HRSG should be 150°C to avoid acid gases from condensing out of the exhaust and corroding the HRSG.[64] Meher-Homji et al. provide more specificity stating that the dew points for natural gas with 30 ppm and 0.3 percent sulfur, are 25 and 121°C, respectively, [65] which indicates that exhaust gas must remain above 25°C for 30 ppm sulfur gaseous fuel and above 121°C for a 0.3 percent sulfur gaseous fuel to avoid acid gas condensation and corrosion. In addition to corrosion concerns associated with sulfur content in the fuel, sulfur compounds can also deposit in the SCR, making it less effective.[66]

Given concerns of corrosion and fouling associated with sulfur content in the fuel, turbine operators will likely elect to remove sulfur from the fuel prior to burning, although, if the sulfur content is relatively low, it could be burned without clean up. Assuming that the operator makes decisions consistent with avoiding fouling and corrosion, the sulfur content of the fuel would likely be a maximum of 30 ppmv and probably less than 10 ppmv.

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[60] Pipeline quality gas is defined in the U.S. under the Acid Rain Program in 40 CFR 72.2 as natural gas with less than 0.5 grains of sulfur per 100 scf of natural gas (0.011 grams/m^3). This is equivalent to 8 ppmv of sulfur in the natural gas.

[61] Meher-Homji, C. et al. Gas Turbine Fuels - System Design, Combustion and Operability. 39th Turbomachinery Symposium (2010). http://turbolab.tamu.edu/proc/turboproc/T39/

[62] Ibid.

[63] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

[64] USEPA, Technology Characterization: Gas Turbines, December 2008 http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

[65] Meher-Homji, C. et al. Gas Turbine Fuels - System Design, Combustion and Operability. 39th Turbomachinery Symposium (2010). http://turbolab.tamu.edu/proc/turboproc/T39/

[66] EPRI. Combustion Turbine Experience and Intelligence Report: 2005: Combustion Turbine/Combined Cycle Technology Developments, Reliability Issues, and Related Market Conditions. EPRI, Palo Alto, CA: 2006. 1010415.

Assuming a 30 ppmv of sulfur in a gaseous fuel, the emissions rate, assuming the fuel has the heat content of natural gas, would be 2.2 g/GJ of SO_2. Poorer quality gases with a lower heating value and the same sulfur concentration would have higher emission rates with respect to the heat input.

In order to assess whether this SO_2 emission rate, based on a sulfur content that is expected to minimize issues of corrosion and fouling, would likely require additional control, emission rates in regulations and permits were reviewed. In the U.S., Standards of Performance for Stationary Combustion Turbines, Subpart KKKK of Part 60, regulates SO_2 from turbines. The emission standard for SO_2 is the same for all turbines regardless of size and most fuel type. Sources can choose to comply with an SO_2 emission limit of 110 g/GJ (0.41 kg/MWh) or to restrict the natural gas sulfur content to 20 grains or less per 100 standard cubic feet (319 ppm). The regulation also includes an emission standard for turbines burning at least 50% biogas of 65 g/GJ of SO_2.

To provide context, emission rate data for gas turbines burning different gaseous fuels was collected from EPA's AP42 Compilation of Air Pollutant Emission Factors;[67] this data is assumed to be representative of long-term averages. Table 5-1 contains this emission rate data and indicates that uncontrolled turbines fired with natural gas, landfill, or digester gas can easily meet the Subpart KKKK emission limits.

Table 5-1. Uncontrolled Gas Turbine SO_2 Emission Factors for Gaseous Fuels

Fuel	Emission Rate (g/GJ)
Natural Gas[a]	1.5
Landfill Gas[a]	19
Digester Gas[a,b]	2.8

[a] AP-42 Compilation of Air Pollutant Emission Factors[68]
[b] Digester Gas Inlet at Joint Water Pollution Control Plant, Carson California[69]

Recent permits were reviewed to identify any turbines burning alternative fuels with sulfur or SO_2 limits, but no permits were found for alternative gaseous fuels.

Because the anticipated sulfur content of gas fuel (i.e., 30 ppmv sulfur or less) is well below limits in the U.S. regulations,[70] it is assumed that SO_2 controls are not necessary. It is also assumed that operators using alternative fuels in their gas turbine would clean the fuel first to remove sulfur to levels acceptable for avoiding corrosion and fouling and that this level would also produce relatively low emissions of SO_2 that are insignificant with respect to needing emissions control.

[67] US EPA – Office of Air Quality Planning and Standards. Compilation of Air Pollutant Emission Factors AP-42, Section 3.1 Stationary Gas Turbines - Supplement F. April 2000.
[68] Ibid.
[69] US EPA – Office of Air Quality Planning and Standards. Compilation of Air Pollutant Emission Factors AP-42, Section 3.1 Stationary Gas Turbines - Background Document. April 2000.
[70] The U.S. regulations are assumed to be the most stringent turbine regulations.

6.0 ADDITIONAL CONSIDERATIONS

The analysis presented in section 4 addresses equipment operating at full load for the full year or, in the case of peaking units operating at full load for 4000 hours in a year; costs and emissions reductions are presented for each model turbine based on one of these two operating scenarios. In reality, utility plants have always had to perform shutdowns and startups or operated at less than full load to match the power needs of the region they service. This need for varying operation and to quickly respond to changing demands has increased over the last decade, so that even combined cycle plants are required to operate at varying capacity. The need for more flexible operations has increased for a variety of reasons including changes in the economy and fuel prices, relying on older power plants, environmental drivers, use of renewable energy sources that provide intermittent power, and issues involving power grid reliability.[71] The power industry operates on a complex web of overlapping issues and economic drivers that demand more flexibility in operations to efficiently provide clean low cost electricity. With today's computer systems all the contributing factors can be analyzed and instantly provide the most effective operating scenario for a power company's fleet. Manufacturers and operators are working to make the power generating equipment respond to these rapidly changing demands without damaging the generating equipment and significantly reducing its useful life span. At the same time, environmental concerns must be addressed and the generating equipment must be able to operate at the load necessary and maintain appropriate levels of emissions.

Part of this overall trend affecting the demand profiles for generating equipment is the pressure to use more forms of renewable energy. Various waste gases, industrial offgases, and produced gases are being used to recovery any heating value that is available. Turbines are being tested with a wide range of gas properties. This section investigates the impacts on air emissions from this trend for more flexible operations including increased startups and shutdowns, varying load levels, and changes in fuel composition. Implications with turbine size cutoffs are also discussed.

6.1 Impacts of Startup and Shutdown

Historically, periods of startup and shutdown were accepted by regulators as periods when emissions could not be controlled and they were often either ignored or exempted from emission limits with ill defined phrases such as "except during periods of startup and shutdown." As emission regulations become more stringent and startup and shutdown events become more prevalent, regulators have begun focusing on these periods to effect additional emissions reductions. Manufacturers have responded with improved technology and process control to reduce the periods of increased emissions.

Aeroderivative turbines can startup rapidly, even less than 10 minutes, but industrial and heavy frame turbines and ancillary equipment, such as HRSGs and SCR cannot be turned off and on at a moment's notice. The equipment must ramp up with different processes coming online as equipment reaches the necessary temperature levels. For example, the temperature at the SCR must reach about 300^{o}C before the system can be turned on. It is typical for this to take as long

[71] Espinoza, Neva, Bill Carson and Rick Roberts, 2014, Managing the Changing Profile of a Combined Cycle Plant, Power Magazine, June 1, 2014. Web access: http://www.powermag.com/managing-the-changing-profile-of-a-combined-cycle-plant/

as 180 minutes for a combined cycle turbine to reach this point. In addition to being a period with little control device affect, during the lower temperatures of startup and shutdown periods incomplete combustion occurs, generating larger quantities of VOC and carbon monoxide, as well as additional NO_x as flow patterns that eliminate hot spots in the combustor establish themselves. If a combined cycle turbine is started and stopped each day, a 3 hour ramping period before the SCR is turned on and 3 hours of time when the SCR is turned off for shutdown (total of 6 hours turned off), would mean that at least 25% of the time the NO_x emissions are not controlled. Without accounting for the fact that the NO_x concentration during these events is higher, having the SCR turned off for 25% of the time represents a decrease in the SCR reduction efficiency from 92% (the value assumed in the Section 4 analysis) to 69%, almost a 4 times increase in overall emissions. This also does not account for the problems of adjusting ammonia injection levels in the SCR as the load and concentration profile changes.

Early in this century, one professional suggested that the emissions profile during startup and shutdown was transient, random and could not be predicted or controlled.[72] Another researcher a year later recognized the numerous factors and complexities contributing to emissions during startup, but observed "However, when making the comparisons of various GE 7FA startups it is apparent that these events are remarkably similar and certain conclusions can be drawn."[73]

From an air quality perspective, emissions from startups and shutdowns depend on the concentration of the pollutant, the flow rate, the duration of the startup or shutdown event, and the number of these events. Permit limitations have focused on all of these factors to some degree, not necessarily in the same permit, but across all of the permits as regulators grapple with methods to limit the emissions, while providing some operating flexibility. Manufacturers have responded with newer designs focusing on event durations. GE's newest generation of the 60 Hz 7HA that have come online in 2013 and 2014, using staged combustion and steam cooling, can reach full output in 10 minutes.[74] Mitsubishi has a similar design that is expected to come out in 2015[75] and Siemen's SGT6-8000H is capable of starting up in less than a 15 minute startup.[76]

Several manufactures have process control software that controls the turbine startup process, including HRSG, steam turbine, and SCR components to ramp equipment up in the most efficient way.[77] Siemen's FACY (FAst CYcling) system has decreased time of startup by about 27 minutes to less than 30 minutes and has increased efficiency during the startup process

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[72] Bivens, Robert J. 2002. Startup and Shutdown NO_x Emissions from Combined-Cycle Combustion Turbine Units, Presented at EPRI CEM User Group Meeting, Chicago, Illinois, May 24, 2002.

[73] Mulkey, Cynthia E., 2003, Evaluation of Nitrogen Oxide Emissions During Startup of Simple Cycle Combustion Turbines. Electronic Theses, Treatises and Dissertations Paper 2200. Web access: http://diginole.lib.fsu.edu/cgi/viewcontent.cgi?article=4044&context=etd&sei-redir=1&referer=http%3A%2F%2Fwww.google.com%2Fcse%3Fcx%3Dpartner-pub-0401106542305152%3A6314965002%26q%3Dturbine%2Bemissions%2Bduring%2Bstartup#search=%22turbine%20emissions%20during%20startup%22

[74] Overton, Thomas W., 2014, Recent Innovations from Gas Turbine and HRSG OEMs, Power Magazine, Vol. 158, No. 6, June 2014.

[75] Overton, Thomas W., 2014, Recent Innovations from Gas Turbine and HRSG OEMs, Power Magazine, Vol. 158, No. 6, June 2014.

[76] http://www.energy.siemens.com/us/pool/hq/power-generation/gas-turbines/SGT5-8000H/gasturbine-sgt5-8000h-h-klasse-performance.pdf

[77] Gulen, S. C, 2013, Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept, Power Engineering, June 12, 2013.

from about 36% to 50%, which saves emissions by reducing the fuel consumed.[78] These systems can also improve load changes throughout the day.

Limitations on emissions during startup and shutdown are sometimes included in air permit limits. Regulators have addressed startup and shutdown emissions in permits in various ways:

- Allow exceedances of the normal control level or emission limits during startup and shutdown, with no limitation on frequency or duration. Sources are allowed to exclude emissions data for each combustion turbine during the startup and shutdown cycle.[79]
- Allow emission exceedance of the short term emission limits, but limit the number of startup and shutdown events in a year.
- Establish specific duration limits for startup and shutdown periods.
- Allow exclusion of CEMS data during startup and shutdown periods from compliance demonstrations, but limit the amount of data that can be excluded. See Table 6-1 excerpted from a Florida permit, as an example. In this permit, the durations of startup and shutdown periods are not limited directly. The amount of data that is excluded from consideration for compliance demonstrations is limited. For example, if the cold startup of the CTG/HRSG lasts 5 hours, only 4 hours of CEMS data can be excluded from the CEMS data used to demonstrate compliance, but one hour of the data cannot be excluded.

Table 6-1. Florida Permit Allows Emissions During Startup and Shutdown Periods to be Excluded from Compliance Demonstrations[80]

Turbine System Status	Definition	Excluded CEMS Data Duration Limitation
STG/HRSG - Cold Startup	Startup following a shutdown of the STG lasting at least 48 hours	8 hours
CTG/HRSG - Cold Startup	Startup after the pressure in the HP steam drum falls below 450 psig for at least a one-hour period.	4 hours
CTG/HRSG - System Warm Startup	Startup when the pressure in the HP steam drum is equal to or greater than 450 psig.	2 hours
Combined Cycle Operations - Shutdown	Shutdown of combined cycle operations	3 hours
CTG/HRSG – System Shutdown	Shutdown of CTG/HRSG operations	2 hours

STG=Steam turbine generator HP=High-pressure
CTG=Combustion turbine generator HRSG=Heat recovery steam generator

[78] Balling, Lothar, Kais Sfar, and Armin Staedtler, 2012, One year of commercial operation in Irsching, presented at PowerGen Asia, Bangkok, October 3-5, 2012.
[79] Florida Power & Light Company - Lauderdale Plant. Florida Department Of Environmental Protection - Air Permit No. 0110037-011-AC. March 2014.
[80] Tampa Electric Company - Polk Power Station. Florida Department Of Environmental Protection - Air Permit No. 1050233-034-AC. March 2013.

- Incorporate emissions during startup and shutdown in an overall annual emissions limit. A Virginia reads "Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown." [81]
- Specify that the SCR be operated when a specific operating temperature is met or when the turbine load reaches a certain percentage of plant net output. Shutdown involves lower risks of catalyst damage.
- Limit the hourly emission rate of NO_x during startup and shutdown periods at a higher level than the emission limit for normal operations. This could be coupled with a number of startup and shutdown event limit or a total number of hours per year the turbine is transitioning between off and at full operation. For example, one permit limited the hourly emission rate for NO_x at 22.5 lb/hr from the turbines during periods of startup/shutdown and limited the number of hours of startup/shutdown to 300 hours for each simple cycle turbine.[82]
- Require a company to control startup emissions using an auto-tuning technology.[83] This would be a control system like the Siemen's FACY system mentioned previously.

6.2 Impacts of Partial Loads

After startup, during shutdown, and at times when less than full power is required, gas turbines operate at partial load. Most turbines maintain the same NO_x concentration in the exhaust from about 50% load up to full load.[84] Below 50% load, the NO_x concentration in the exhaust is much higher, but the emission rates begin to drop off as the flow rate reduces faster than the concentration increases.[85] Turbines are designed to quickly get to 50% load in the startup sequence to limit the number of minutes the turbine is operating when the emissions concentrations are high.[86] As discussed in Section 6.1, the ramping up process can take several minutes, but new turbines are being offered that significantly reduce this time.

While electric efficiency tends to drop under partial load conditions, overall efficiency for cogeneration installations continue to have high efficiency under part load conditions. The decrease in electric efficiency from the gas turbine under partial load results in a relative increase in heat available for recovery in the HRSG. This can be a significant operating advantage for applications in which the economics are driven by a high thermal energy demand.

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[81] Virginia Electric and Power Company - Bear Garden Generating Station. Virginia Department of Environmental Quality. Permit Number: BRRO-32004. Issued January 1, 2014.

[82] Black Hills Corporation - New Construction of Cheyenne Generating Station - Permit No CT-12636 issued August 28, 2012.

[83] Florida Power & Light Company - Replacement of Twenty Four Gas Turbine Peaking Units with Five Simple Cycle Combustion Turbine Electric Generators. Draft Permit No PSD-FL-423 issued February 27, 2014. (page 16 of 38). http://www.dep.state.fl.us/air/emission/construction/fort_lauderdale/PSD-423_TEPD.pdf

[84] Gulen, S.C., 2013, "Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept" Power Engineering. < http://www.power-eng.com/articles/print/volume-117/issue-6/features/gas-turbine-combined-cycle-fast-start-the-physics-behind-the-con.html>

[85] Macak III, Joseph J., 2001, *Evaluation of Gas Turbine Startup Shutdown Emissions for New Source Permitting*. 94th A&WMA Annual Conference.

[86] Gulen, S.C., 2013, "Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept" Power Engineering. < http://www.power-eng.com/articles/print/volume-117/issue-6/features/gas-turbine-combined-cycle-fast-start-the-physics-behind-the-con.html>

6.3 Impacts of Varying Gas Composition

Gas turbines were designed to handle the normal fluctuations in composition of natural gas.[87] Typical composition of natural gas includes 90% methane or more and up to 5% inerts, with the remainder being other organic compounds.[88] In the last several years operators have become more interested in using a variety of gases in combustion turbines. These gases include digester gas, landfill gas, syngas, coke oven gas, and gas from the gasification of coal, biomass, municipal waste, wood, etc. Turbine manufacturers provide owners with fuel specification requirements for each turbine to ensure the turbine operates as expected and achieves a reasonable lifespan. For turbines with DLN combustors, the fuel specifications are much narrower than conventional (diffusion) combustors.[89] The composition of the fuel has a large affect on turbine performance; fuel characteristics such as heating value, flame temperature, flammability limits, autoignition delay time, wobble index, dew point, and flame stability (including turbulent flame speed, velocity of fuel) all play a role in the turbine's performance.[90] With DLN combustors, the turbine must react to the specific fuel composition, alter the fuel-to-air ratio to compensate for the different composition, and maintain the flame temperature constant in order to keep the NO_x emissions at expected levels, while making sure the flame does not become instable.[91] In addition to affecting the performance, instable flames can damage the turbine and affect lifespan.[92]

In some cases, operators may elect to burn the alternative fuels in the HRSG only and continue burning natural gas in the turbine. Turbine systems that include a duct burner (e.g., combined cycled power plants or cogeneration systems) offer the flexibility of using these lower quality fuels with no (or minimal) cleanup. This is common for plants located at facilities that produce low quality gas as part of the larger process (e.g., oil and gas refineries, oil sands extraction plants, etc.). However, as noted in Section 4, high levels of sulfur-containing compounds in the fuel can cause corrosion or fouling issues in both the HRSG and the SCR under the right conditions. This fouling effect may be mitigated by a high dilution factor of the fuel used in the duct burner relative to the flow rate of the turbine exhaust gas.

Conventional diffusion combustor turbines do not have much difficulty burning fuels of all varieties. NO_x emissions must be controlled using wet injection and/or SCR. For DLN combustors, expanding fuel flexibility has been more difficult, but progress has been made. This section focuses on the capability of DLN to burn alternative fuels.

There are three general categories of alternative fuels including:

1. Fuels with inert gases (e.g., nitrogen and carbon dioxide);

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[87] Wisniewski, K.J. and Handelman, S., 2010, "Expanding Fuel Flexibility Capability in GE's Aeroderivative Engines," Proceedings of the ASME Turbo Expo, Glasgow, United Kingdom, ASME Paper No. GT2010-23546.
[88] Ibid
[89] Meher-Homji, C. et al. Gas Turbine Fuels - System Design, Combustion and Operability. 39th Turbomachinery Symposium (2010). http://turbolab.tamu.edu/proc/turboproc/T39/
[90] Kurz, Rainer X. and Saeid Mokhatab, 2012, Important Properties for Industrial Gas Turbine Fuels, Pipeline & Gas Journal, June 2012, Vol. 239, No. 6.
[91] Meher-Homji, C. et al. Gas Turbine Fuels - System Design, Combustion and Operability. 39th Turbomachinery Symposium (2010). http://turbolab.tamu.edu/proc/turboproc/T39/
[92] Welch, Michael and Brian M. Igoe, 2013, Gas Turbine Fuel and Fuel Quality Requirements for use in Industrial Gas Turbine Combustion, Proceedings of the Second Middle East Turbomachinery Symposium, March 2013, Doha, Qatar.

2. Fuels containing significant amounts of hydrogen and/or carbon monoxide; and

3. Fuels with hydrocarbons with chains of multiple carbons (C2+).[93]

The ability for turbines to burn these fuels is discussed below.

6.3.1 Turbines Burning Fuels with Inerts.

Turbine manufacturers have increased the capability of DLN combustors and many can now perform well burning fuels with high inert concentrations.[94] GE performed tests on their aeroderivative DLN combustion turbines using as much as 50% nitrogen with natural gas. The operating conditions of the turbine were adjusted to optimize flame temperature. The turbine was able to burn all mixtures of nitrogen and natural gas, with no increase in NO_x.[95]

6.3.2 Turbines Burning Fuels with Hydrogen and Carbon Monoxide.

The unique combustion properties of hydrogen and carbon monoxide have made it difficult for vendors to find solutions for DLN combustors burning fuels with hydrogen and carbon monoxide.[96] The U.S. DOE has provided grants to turbine manufactures to develop hydrogen-fueled turbines. The goal is to develop the needed turbines to be used in integrated gasification combined cycle plants, so that gasified coal can become a realistic fuel source. These turbines are to meet single digit NO_x emissions.[97] All heavy frame turbine manufactures have made strides towards burning fuels with high quantities of hydrogen and/or carbon monoxide. The limitations and performance varies and are always improving.

6.3.3 Turbines Burning Fuels with Multi-Carbon Hydrocarbons.

Fuels with chains of multiple carbons (C2+) have higher flame speeds and temperatures, which can cause flashback in a DLN combustor. Flashback can cause deterioration of the turbine and the higher temperatures increase NO_x emissions. GE tested their aeroderivative DLN combustion turbine using fuels with higher concentration of ethane, than normally found in natural gas. Based on these tests, GE was able to increase the limit of C2+ compounds in fuels for their DLN combustors from 15% to as high as 35% in some models.[98] Other manufacturers have made similar gains.

[93] Wisniewski, Karl J. and Steve Handelsman, 2010, Expanding Fuel Flexibility Capability in GE's Aeroderivative Engines, presented at ASME Turbo Expo, Glasgow, UK.

[94] Welch, Michael and Brian M. Igoe, 2013, Gas Turbine Fuel and Fuel Quality Requirements for use in Industrial Gas Turbine Combustion, Proceedings of the Second Middle East Turbomachinery Symposium, March 2013, Doha, Qatar.

[95] Wisniewski, Karl J. and Steve Handelsman, 2010, Expanding Fuel Flexibility Capability in GE's Aeroderivative Engines, presented at ASME Turbo Expo, Glasgow, UK.

[96] Welch, Michael and Brian M. Igoe, 2013, Gas Turbine Fuel and Fuel Quality Requirements for use in Industrial Gas Turbine Combustion, Proceedings of the Second Middle East Turbomachinery Symposium, March 2013, Doha, Qatar.

[97] NETL, 2012, The Energy Lab Program Facts – Hydrogen Turbine Program, Program 108, April 2012.

[98] Wisniewski, Karl J. and Steve Handelsman, 2010, Expanding Fuel Flexibility Capability in GE's Aeroderivative Engines, presented at ASME Turbo Expo, Glasgow, UK.

6.4 Impacts of Size Cutoffs

Available turbine models are shown in Table 6-2. Many of the turbines listed are likely available with water injection and/or with standard combustors. This could not be verified in all cases.

Table 6-2. Turbine Sizes by Manufacturer and Availability of Controls

Manufacturer	Frequency	Model	MW	Controls	NO_x level
PW Power		MobilePac	24	WI	25
PW Power		SwiftPac 25	25	DLN	
Siemens Energy	50/60	SGT-600	25	DLN	25
PW Power		MobilePac	26	WI	25
Rolls Royce	50/60	RB211-G62 DLE	27	DLN	25
GE O&G Frame		MS5001	27	Standard Combustor	
GE Energy Aeroderivative	50	LM2500PH	27		
Mitsubishi	50/60	MFT-8	27		
GE Energy Aeroderivative	60	LM2500PH	28		
GE Energy Aeroderivative	50	LM2500PK	29	WI	25
GE Energy Aeroderivative	60	LM2500PR	30	DLN	25
GE Energy Aeroderivative	50	LM2500PR	30	DLN	25
Kawasaki Heavy Industries		L30A	30	DLN	15
Rolls Royce	50/60	RB211-GT62 DLE	30	DLN	25
GE O&G	50/60	PGT25+	30		
Mitsubishi	50/60	MF-221	30		
GE O&G Frame		MS5002E	31	DLN	
GE Energy Aeroderivative	60	LM2500PK	31	WI	25
PW Power		SwiftPac 30	31	WI	25
Hitachi	50/60	H-25	32	DLN	15
Rolls Royce	50/60	RB211-GT61 DLE	32	DLN	25
Siemens Energy	50/60	SGT-700	32	DLN	15
GE Energy Aeroderivative	50	LM2500+RD	33	DLN	
GE Energy Aeroderivative	60	LM2500+RD	33	DLN	
GE O&G	50/60	PGT25+G4	33	DLN	25
Siemens Energy	50/60	SGT-750	36	DLN	15
GE Energy Aeroderivative	60	LM2500+ RC	36	WI	25

Table 6-2. Turbine Sizes by Manufacturer and Availability of Controls

Manufacturer	Frequency	Model	MW	Controls	NO_x level
GE Energy Aeroderivative	50	LM2500+RC	36	WI	25
GE O&G Frame		MS6001B	42	DLN	15
GE O&G Frame		MS6001B	42	Standard Combustor	
Rolls Royce	50/60	RB211-H63 WLE	42	WI	25
GE Energy Aeroderivative	50	LM6000PD	43	DLN	25
GE Energy Aeroderivative	60	LM6000PD	43	DLN	25
GE Energy Aeroderivative	60	LM6000PF	43	DLN	15
GE Energy Aeroderivative	50	LM6000PF	43	DLN	15
GE Heavy Duty	50/60	6B 3-series (Opt 2)	43	DLN	4
GE O&G	50/60	LM6000PD	43	DLN	25
GE O&G	50/60	LM6000PF	43	DLN	15
GE Heavy Duty	50/60	6B 3-series (Opt 1)	43	Standard Combustor	
GE Energy Aeroderivative	50	LM6000PC	43	WI	25
GE Energy Aeroderivative	60	LM6000PD Sprint	47	DLN	25
GE Energy Aeroderivative	50	LM6000PD Sprint	48	DLN	25
GE Energy Aeroderivative	50	LM6000PF Sprint	48	DLN	15
GE Energy Aeroderivative	60	LM6000PF Sprint	48	DLN	15
Siemens Energy	50/60	SGT-800 (option 1)	48	DLN	15
GE Energy Aeroderivative	60	LM6000PC	49	WI	25
Siemens Energy	50/60	SGT-900	50	DLN	
GE Energy Aeroderivative	50	LM6000PH	51	DLN	15
GE Energy Aeroderivative	60	LM6000PH	51	DLN	15
PW Power		SwiftPac 50 DLN	51	DLN	
Siemens Energy	50/60	SGT-800 (option 2)	51	DLN	15
GE O&G	50/60	LM6000PG	51	Standard Combustor	
GE Energy Aeroderivative	50	LM6000PC Sprint	51	WI	25
GE Energy	60	LM6000PC	51	WI	25

Table 6-2. Turbine Sizes by Manufacturer and Availability of Controls

Manufacturer	Frequency	Model	MW	Controls	NO_x level
Aeroderivative		Sprint			
GE O&G	50/60	LM6000PG	51	WI	25
GE Energy Aeroderivative	50	LM6000PH Sprint	53	DLN	15
GE Energy Aeroderivative	60	LM6000PH Sprint	53	DLN	15
Rolls Royce	50	Trent 60 DLE	53	DLN	25
GE Energy Aeroderivative	50	LM6000PG	53	Standard Combustor	
GE Energy Aeroderivative	60	LM6000PG	53	Standard Combustor	
Rolls Royce	60	Trent 60 DLE	54	DLN	25
GE Energy Aeroderivative	50	LM6000PG	56	WI	25
GE Energy Aeroderivative	60	LM6000PG	56	WI	25
GE Energy Aeroderivative	50	LM6000PG Sprint	58	WI	25
GE Energy Aeroderivative	60	LM6000PG Sprint	58	WI	25
Rolls Royce	60	Trent 60 DLE ISI	62	DLN	25
PW Power		SwiftPac 60	62	WI	25
Rolls Royce	60	Trent 60 WLE	63	WI	25
Rolls Royce	50	Trent 60 DLE ISI	64	DLN	25
Rolls Royce	50	Trent 60 WLE	66	WI	25
Rolls Royce	60	Trent 60 WLE ISI	66	WI	25
Rolls Royce	50	Trent 60 WLE ISI	66	WI	25
GE Heavy Duty	50/60	6F 3-series	78	DLN	15
GE O&G Frame	60	MS7001EA	85	Standard Combustor	
GE Heavy Duty	60	7E 3-series	89	DLN	4
GE Heavy Duty	60	7E 3-series	89	Standard Combustor	
GE O&G	50/60	LMS100	98	DLN	
GE Energy Aeroderivative	60	LMS100PB	99	DLN	25
GE Energy Aeroderivative	50	LMS100PB	100	DLN	25
GE Energy Aeroderivative	50	LMS100PA	103	WI	25
GE Energy Aeroderivative	60	LMS100PA	104	WI	25
Hitachi	60	H-80	111	DLN	15
Hitachi	50	H-80	112	DLN	15

Table 6-2. Turbine Sizes by Manufacturer and Availability of Controls

Manufacturer	Frequency	Model	MW	Controls	NO_x level
Siemens Energy	60	SGT6-2000E	112	DLN	25
Alstrom	50	GT11N2	114	DLN	25
Mitsubishi	60	M501DA	114		
Alstrom	60	GT11N2	115	DLN	25
GE O&G Frame	50	MS9001E	126	DLN	15
GE O&G Frame	50	MS9001E	126	Standard Combustor	
GE Heavy Duty	50	9E 3-series	128	DLN	5
Mitsubishi	50	M701DA	144		
Siemens Energy	50	SGT5-2000E	166	DLN	25
GE Heavy Duty	60	7F 3-series	185	DLN	
Mitsubishi	60	M501F3	185	DLN	9 or 15
Alstrom	50	GT13E2	203	DLN	15
GE Heavy Duty	60	7F 5-series	216	DLN	9
Alstrom	60	GT24	231	DLN	15
Siemens Energy	60	SGT6-5000F	232	DLN	9
GE Heavy Duty	50	9F 3-series	261	DLN	15
Mitsubishi	60	M501G1	268	DLN	15
Siemens Energy	60	SGT6-8000H	274	DLN	25
Mitsubishi	60	M501GAC	276	DLN	15
Siemens Energy	50	SGT5-4000F	292	DLN	25
GE Heavy Duty	50	9F 5-series	298	DLN	25
Mitsubishi	60	M501JAC	310		
Mitsubishi	50	M701F3	312	DLN	9 or 15
Mitsubishi	50	M701F4	324		
Alstrom	50	GT26	326	DLN	15
Mitsubishi	60	M501J	327		
Mitsubishi	50	M701G2	334		
GE Heavy Duty	50	9F 7-series	339	DLN	
Mitsubishi	50	M701F5	359		
Siemens Energy	50	SGT5-8000H	375	DLN	25
Mitsubishi	50	M701J	470		

7.0 CONTROL TECHNOLOGY PERFORMANCE CAPABILITY AND EMISSION LIMITS

ERG investigated air permits issued to new construction projects in the United States. These approvals were issued under the U.S. Prevention of Significant Deterioration permitting program in which new equipment meeting certain emissions levels, must be installed with BACT level controls in place. The process to determine the BACT control level is similar to the process conducted in this study and reported in Section 3. This was not an exhaustive search for permits, but it is believed to include the majority of PSD BACT turbine permits issued over the last 6 years.

To identify recent BACT analyses, ERG searched in the U.S. EPA's RBLC database and searched EPA and U.S. state air permitting websites. The data entered into the RBLC are provided by State and local agencies. Submittals represent these agencies' permitting and reporting efforts for BACT analyses, as well as other control technology assessments. Submittals to the RBLC are voluntary.

Permits can have BACT control limits of pounds per hour, pounds per million Btu, or tons per year instead of ppmv, but for the permits found for this report, all were expressed as ppmvd at 15% O_2. The BACT control limits found are separated into those for peaking units and those for combine cycle turbines. All single cycle turbines found in permits were either labeled as peaking units or were given an hour limit.

This section contains a discussion about the combined cycle turbine limits in Section 7.1, peaking unit permit limits in Section 7.2, additional turbine limit considerations in Section 7.3, and conclusions in Section 7.4.

7.1 Combined Cycle Turbine Permit Limits

Table 7-1 lists all of the BACT analyses found for combined cycle turbines. All of the permits for combined cycle turbines indicate that SCR is the BACT level of control. Most of these, 23 out of the 26 permits, gave the performance level of 2 ppmvd at 15% O_2. The remaining three permits had limits close to 2 ppmvd, with two requiring 3 ppmvd and one with 2.5 ppmvd as the limit. All three of these were issued in 2012. It is interesting to note that two of the states that issued these permits, Ohio and Delaware, both issued permits in 2013 with the 2 ppmvd limit. Based on the data collected it would be difficult to refute that SCR on a combined cycle turbine is BACT, assuming no additional issues or situational factors exist.

Some of the BACT permits list both DLN and SCR as BACT. Eleven out of the 26 combined cycle permits only specified that SCR was BACT. This does not mean that the turbine does not have DLN. In fact a conventional diffusion turbine would not be expected to meet the BACT limit of 2 ppmvd without DLN or wet injection. SCR are capable of efficiencies of 80 to 95 percent. Turbines with conventional diffusion combustors are expected to have uncontrolled NO_x emissions over 100 ppmv at 15% O_2.[99] Therefore, a 2 ppmvd emission limit could not be met with an SCR, unless the turbine has a DLN combustor or is a conventional combustor with wet injection.

[99] EPA, 1993, Alternative Control Techniques Document NO_x Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993.

Table 7-1. BACT Control Levels for Combined Cycle Turbines

Mode	Year	Turbine Model	Combustion Turbine Size (MW)	State	Number of Combustion Turbines	NO_x Limit (ppmvd @ 15% O_2)[1]	Average Time	Control Method
CC	2014	Siemens 5000	208	PA	1	2	-	SCR
CC	2013	Undecided	200	TX	2	2	24-hr	SCR
CC	2013	Undecided	274	OH	2	2	-	DLN+SCR
CC	2013	GE 7FA.05	184	VA	2	2	24-hr	DLN+SCR
CC	2013	-	450	PA	2	2	-	SCR
CC	2013	Undecided	200	PA	3	2	-	SCR
CC	2013	Mitsubishi M501 GAC	272	VA	3	2	1-hr	DLN+SCR
CC	2013	Undecided	472	PA	2	2	-	SCR
CC	2013	GE 7FA	184	DE	1	2	1-hr	DLN+SCR
CC	2013	GE 7FA	165	FL	4	2	24-hr	DLN+SCR
CC	2013	-	-	MI	2	2	24-hr	DLN+SCR
CC	2012	Undecided	250	FL	3	2	30-day	DLN+SCR
CC	2012	Mitsubishi M501G	-	MA	-	2	-	SCR
CC	2012	GE 7FA	184	OH	4	3	3-hr	DLN+SCR
CC	2012	-	338	IN	4	2	3-hr	DLN+SCR
CC	2012	GE LM6000[2]	50	DE	1	2.5	1-hr	SCR
CC	2012	Siemens 501F	180	TX	1	2	3-hr	SCR
CC	2012	Undecided	468	PA	2	2	-	DLN+SCR

Table 7-1. BACT Control Levels for Combined Cycle Turbines

Mode	Year	Turbine Model	Combustion Turbine Size (MW)	State	Number of Combustion Turbines	NO_x Limit (ppmvd @ 15% O_2)[1]	Average Time	BACT Control Method
CC	2012	Siemens 501F	180	TX	5	2	3-hr	SCR
CC	2012	GE 7FA	184	TX	3	2	24-hr	SCR
CC	2012	GE LM6000[2]	50	WY	2	3	1-hr	DLN+SCR
CC	2011	Undecided	265	FL	3	2	30-day	DLN+SCR
CC	2011	GE 7FA	180	CA	2	2	1-hr	DLN+SCR
CC	2011	GE 7FA	154	CA	2	2	1-hr	DLN+SCR
CC	2010	GE 7FA	170	FL	2	2		DLN+SCR
CC	2009	GE LM6000PD[2]	42	CA	1	2	1-hr	SCR

CC – combined cycle; SC – simple cycle; DLN – dry low NO_x; SCR-selective catalytic reduction; BACT- best available control technology.

[1] Most permits had concentration limits specified in ppmvd @ 15% O_2, although some specified only ppm. For the purposes of this table, it has been assumed all concentration limits are in ppmvd @ 15% O_2.

[2] Aero-derivative turbine model.

[3] Many of the California Air Districts define BACT more consistent with the U.S. EPA federal definition of LAER. This permit indicates that this is “BACT”; however, since this is consistent with LAER in other locations of the United States we have listed it as “LAER”.

[4] Data source RBLC.

The averaging times for each emission limit are also listed in Table 7-1 if one was found in the permit. Averaging times can average out operational variability. The shorter an averaging time, the more stringent, because less time is available to average out any spikes in emissions. Not all combined cycle permits had averaging times. Of those that did, about a third (7 out of 18) had an averaging time of 1-hour, which is also the shortest averaging time specified in any of the permits. In the 2009 Report, less than 20% of the permits with averaging times had 1-hour as the averaging times. All others were greater than 1 hour, with most limits having an averaging time of 3-hours (11 out of 37) or 24-hours (9 out of 37). There was one annual averaged limit in the 2009 Report and no monthly or 30-day averages. In Table 7-1, there are no annual averages and the longest averaging time allowed was 30-days included in two permits. The increased proportion of 1-hour averaged emission limits from the 2009 Report until now could indicate a move towards an increase in stringency of the emission limit.

In the 2009 Report, some of the combined cycle permits included annual hour limits to restrict the time the duct burners were operated, but none were found for these permits. There were HRSG/SCR bypass emission limits in some of the combined cycle permits from 2003 to 2008, shown in Table 3-8 in the 2009 Report; some also had hour limits for the bypass. No bypass limit was found in the 2009 to 2014 permits (Table 7-1). All but four of the combined cycle turbines in Table 7-1 have duct burners. The BACT limit applies to the exhaust gas from the combined cycle turbine including exhaust from the duct burners.

7.2 Peaking Unit Permit Limits

Table 7-2 lists the BACT analysis results from recent permits for turbines that are most likely new peaking turbines. These were assumed to be peaking units because the permit listed an hour limitation (or fuel limit that curtailed hours), or they were specifically identified as being a “peaking unit.”

In peaking turbine permits, hour limitations ranged from 2,500 to 7,350 hours per year for turbines. The 7,350 hours limit seems to be an outlier; the limit is only a 16% reduction from every hour of the year. The next closest limit is 5,000 hour. The other entries are all between 2,500 and 5,000 hours. The NO_x limits for the peaking turbines range from 2.5 to 25 ppmv, with 8 out of 12 permits requiring SCR as BACT. Five of these permits have limits of 2.5 ppmv and the other three are limited at 5 ppmv. It is interesting to note that the 5 permits with the lowest limits are for facilities located in California and Connecticut. California’s and Connecticut’s ambient ozone concentrations are considered high across most of the state; therefore, facilities in these areas are generally subject to more stringent regulatory requirements. The rest of the peaking units are located in Florida, North Dakota, Wyoming, and Montana, which have not had air quality issues.[100] North Dakota, Montana, and Wyoming are rural states and Florida is a very populated state but does not have as many industrial sources as other states its size. This may partially explain the wider spread of emission limits among the peaking units, compared to the limits for combined cycle plants. Also, the BACT emission limits for combined cycle plants have

[100] However, in 2012, a portion of Wyoming was declared a nonattainment area for ozone, which means that the ambient ozone concentration is higher than the U.S. National standard. This is the first time a portion of Wyoming has been declared a nonattainment area for ozone. It would be expected that permits for turbines in this nonattainment area would be more stringent after the designation in 2012.

Table 7-2. BACT Control Levels for Peaking Units

Mode	Year	Turbine Model	Combustion Turbine Size (MW)	Limited Hours per Combustion Turbine	State	Number of Combustion Turbines	NO_x Limit (ppmvd @ 15% O_2)[1]	Averaging Time	Control Method
SC	2014	GE LMS100[2]	100	4,335	CA	3	2.5	1-hr	WI + SCR
SC	2014	GE LM 6000PC Sprint[2]	50	4,966	CT	4	2.5		WI + SCR
SC	2013	GE 7FA.05	223	Max. 5,000 Avg. 3,390	FL	2	9	24-hr	DLN
SC	2013	GE LM 6000PC Sprint[2]	46.5	2,900	CA	1	2.5		WI + SCR
SC	2013	GE LM 6000PF Sprint[2]	45	3,600	ND[3]	3	5	4-hr	SCR
SC	2013	GE LM 6000 PC Sprint[2]	46	3,600	ND[3]	3	5	4-hr	WI + SCR
SC	2013	GE PG 7121 (7EA)	88	7,350	ND[3]	1	9	4-hr	DLN
SC	2013	Siemens SGT6-5000F	200	3,300	FL	5	9	24-hr	DLN
SC	2012	Pratt and Whitney FT8-3[2]	30	4,000	CA	8	2.5	1-hr	SCR
SC	2012	GE LM6000[2]	40	-	WY	3	5	1-hr	DLN+SCR
SC	2009	GE LMS100[2]	100	3,400	MT	1	25	1-hr	WI
SC	2009	GE LM 6000PC[2]	50	3,200	CA	1	2.5	1-hr	WI + SCR

CC – combined cycle; SC – simple cycle; DLN – dry low NO_x; WI-Wet Injection; SCR-selective catalytic reduction; BACT- best available control technology; hr- hour; ppmvd- parts per million by volume on a dry basis; and PA-power augmentation.

[1] Most permits had concentration limits specified in ppmvd @ 15% O_2 although some only specified ppm. For the purposes of this table, it has been assumed all concentration limits are in ppmvd @ 15% O_2.

[2] Aero-derivative turbine model.

[3] Data source RBLC.

not varied much over the last several years, which does not allow states much flexibility in establishing BACT.

7.3 Additional Turbine Limit Considerations

Sections 7.1 and 7.2 address the BACT limits for combined cycle turbines and peaking units, respectively. The BACT limits apply to these units because emission increases from the construction of the turbines was more than the applicability level for PSD permits, which require BACT to be assessed and applied. Turbines that are greater than 25 MW, with an exhaust concentration of NO_x of 25 ppmdv at 15% O_2 and operating full time (8,400 hours or more per year) would likely require a PSD permit and be subject to BACT. Reducing the exhaust concentration could make it possible to install a turbine larger than 25 MW, while avoiding PSD; for example, a 41 MW turbine emitting 15 ppmdv and operating 8,400 hours, could possibly avoid triggering PSD depending on the details of the construction. For simplicity, however, and because this report is limited to turbines greater than 25 MW, it can be assumed that the vast majority of turbines operating full time, would be subject to BACT and BACT for these turbines is addressed in Section 7.1. For peaking turbines, which operate fewer hours than 8,400, there are several scenarios in which turbines can be installed that would not trigger BACT. Table 7-3 shows some of the scenarios that would not be expected to trigger PSD or apply BACT controls.

Although these smaller peaking units (Table 7-3) would not be subject to PSD permitting and BACT controls, the PSD regulations act to reduce emissions of these permits because facilities will try to install turbines that do not trigger PSD. For example, a power company that needs about 80 MW more of peak power would likely install a turbine with a DLN combustor getting 15 ppmdv NO_x or less and limit their operations to 4,200 hours per year. This helps them avoid the requirements of PSD, but, at the same time, better equipment is being installed than what might have been if the threat of BACT controls did not exist. The scenarios in Table 7-3, are based on simple situations where the turbines are the only source of NO_x being added. For those scenarios for turbines added at new facilities, the turbines shown would have estimated maximum emissions of just less than 100 tons of NO_x per year (91 tonnes/year); and for turbines added to existing facilities they would emit a maximum of 40 tons of NO_x per year (36 tonnes/year).

Table 7-3. Example Gas Turbines Likely Not to be Subject to PSD and BACT Control Limits

Total Maximum Capacity Size (MW)	Maximum Total Annual Operating Hours	Outlet NO_x Concentration (ppmvd)
Turbines Installed at New Facilities		
49	4,200	25
82	4,200	15
30	2,000	87
73	2,000	35
104	2,000	25
173	2,000	15
60	1,000	87
146	1,000	35
207	1,000	25
345	1,000	15
Turbines Installed at Existing Facilities		
33	4,200	15
29	2,000	35
41	2,000	25
69	2,000	15
208	2,000	9
24	1,000	87
59	1,000	35
83	1,000	25
138	1,000	15

7.4 Conclusions

7.4.1 *Summary of Costs and Emission Reductions*

Table 7-4 summarizes the emissions, cost effectiveness ($/tonne), and the cost impact ($/kW) for installing SCR and ULNB at the various sizes and loads analyzed. Table 7-5 provides this information for cogeneration systems. The cost effectiveness for a given model is calculated by dividing the total annual cost by the annual NO_x reduction in tonnes. The results show that it is more cost effective to install SCR on larger turbines than on smaller turbines. Also, installing and operating an SCR on combined cycle systems is more cost effective than for single cycle turbines, and it is even more cost effective to install SCR on combined cycle systems without burners. These results are not unexpected given that there are economies of scale for SCR units; as SCR increase in size their costs rise, but not in proportion to the amount of emissions reduced.

The cost effectiveness for installing UDLN turbines is much more cost effective than installing SCR, but, as expected, the emissions with UDLN in comparison to SCR are much higher. The cost effectiveness for the UDLN is relatively flat because the costs were based on a linear relationship with turbine size and the emissions are proportional to turbine size.

The cost effectiveness values for SCR units controlling peaking units are the highest (least cost effective); it is more costly to remove a tonne of NO_x for peaking units than for a base unit of comparable size. With peaking units operating only partially throughout a year, it is not as cost effective to install and operate an SCR. Although the SCR capital costs for peak and base units are similar, fewer tonnes are removed at a peak unit due to reduced operation. The most cost effective operating scenario and size combination is an SCR installed at a 300 MW combined-cycle base unit with duct burners.

The results in Table 7-5 for cogeneration systems show similar trends to those for single and combined cycle turbines. For all scenarios investigated, in both Tables 7-4 and 7-5, the use of a LNB duct burner instead of a conventional burner improved the cost effectiveness. The LNB are relatively inexpensive, but achieve significant emission reductions. For example, for the ULNB case, the difference between the emissions with LNB and conventional burners is 67 tonne/yr of NOx for the smallest turbine and 396 tonnes for the largest turbine investigated.

Table 7-4. Comparison of NO_x Emissions and Control Costs for Simple and Combined Cycle Turbines

Model Unit Description	Total Facility Net Power Output (MW)[1]	Emissions if SCR is Applied (tonne/yr)	Emissions if ULNB is Applied (tonne/yr)	SCR Cost Effectiveness ($/tonne)	ULNB Cost Effectiveness ($/tonne)	SCR Cost Impact ($/kW)	ULNB Cost Impact ($/kW)
50 MW - SC - Peak	50	7.35	55.2	9,615	3,355	16	2.5
113 MW - SC - Peak	113	16.5	124	8,814	3,355	15	2.5
50 MW - SC - Base	50	14.7	110	5,980	1,678	20	2.5
113 MW - SC - Base	113	33.1	248	5,179	1,678	18	2.5
175 MW - SC - Base	175	51.5	386	4,950	1,678	17	2.5
300 MW - SC - Base	300	88.3	662	4,776	1,678	16	2.5
50 MW - CC - Base	78	14.7	110	4,426	1,678	9.6	1.6
113 MW - CC - Base	168	33.1	248	3,625	1,678	8.3	1.7
175 MW - CC - Base	277	51.5	386	3,396	1,678	7.3	1.6
300 MW - CC - Base	467	88.3	662	3,222	1,678	7.0	1.6
50 MW - CC - Base w/ DB	90	21.3	193	3,288	1,678	9.0	1.4
113 MW - CC - Base w/ DB	191	46.7	418	2,795	1,678	7.9	1.5
175 MW - CC - Base w/ DB	317	74.9	678	2,567	1,678	7.0	1.4
300 MW - CC - Base w/ DB	535	127	1,150	2,464	1,678	6.8	1.4
50 MW - CC - Base w/ DB LNB[2]	90	17	145	3,233	1,063	9.0	1.4
113 MW - CC - Base w/ DB LNB[2]	191	39	320	2,750	1,093	7.9	1.5
175 MW - CC - Base w/ DB LNB[2]	317	61	509	2,521	1,053	7.0	1.4
300 MW - CC - Base w/ DB LNB[2]	535	105	867	2,419	1,061	6.8	1.4

Table 7-4. Comparison of NO_x Emissions and Control Costs for Simple and Combined Cycle Turbines

Model Unit Description	Total Facility Net Power Output (MW)[1]	Emissions if SCR is Applied (tonne/yr)	Emissions if ULNB is Applied (tonne/yr)	SCR Cost Effectiveness ($/tonne)	ULNB Cost Effectiveness ($/tonne)	SCR Cost Impact ($/kW)	ULNB Cost Impact ($/kW)

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

[1] The net power shown applies to the ULNB values. For SCR, the power should be derated by 0.5%.

[2] The values for these scenarios include the impact of the LNB duct burner, as well as the referenced control. For example, the SCR Cost Effectiveness column shows the cost effectiveness of the combined SCR-LNB control.

Table 7-5. Comparison of NO_x Emissions and Control Costs for Cogeneration Systems

Model Unit Description	Total Facility Net Power Output (MWe)[1]	Total Facility Net Heat Output (MWth)[1]	Emissions if SCR is Applied (tonne/yr)	Emissions if ULNB is Applied (tonne/yr)	SCR Cost Effectiveness ($/tonne)	ULNB Cost Effectiveness ($/tonne)
50 MW – CHP	50	46	14.7	110	4,426	1,678
113 MW – CHP	113	89	33.1	248	3,625	1,678
175 MW - CHP	175	165	51.5	386	3,396	1,678
300 MW - CHP	300	270	88.3	662	3,222	1,678
50 MW - CHP w/ DB	50	72	23.9	226	3,018	1,678
113 MW - CHP w/DB	113	142	52.1	486	2,593	1,678
175 MW – CHP w/DB	175	256	84.2	795	2,374	1,678
300 MW - CHP w/DB	300	422	143	1,345	2,286	1,678
50 MW - CHP w/ DB LNB[2]	50	72	19	159	2,955	907
113 MW - CHP w/ DB LNB[2]	113	142	41	348	2,540	940
175 MW - CHP w/ DB LNB[2]	175	256	65	558	2,320	897
300 MW – CHP w/ DB LNB[2]	300	422	111	949	2,234	907

SC = Simple Cycle; CC = Combined Cycle; DB = Duct Burner; LNB = Low NO_x Burner; all dollars are in 2013 US dollars

1 The net power and heat shown applies to the ULNB values. For SCR, the power and heat should be derated by 0.5%.

2 The values for these scenarios include the impact of the LNB duct burner, as well as the referenced control. For example, the SCR Cost Effectiveness column shows the cost effectiveness of the combined SCR-LNB control.

7.4.2 *Setting Turbine Emission Limits*

To set the specific emission limit values to be used in permits or regulations, there are many things to consider and address. Based on our review of the costs and BACT limitations in the U.S., it appears that there could be at least three subcategories of turbines each with their own regulatory requirements, including:

1. Small Peaking units and/or units with few operating hours. The cost effectiveness for peaking units is much higher than the other categories of turbines. Smaller peaking units and ones that would have fewer operating hours would have high cost effectiveness for an SCR because of the much lower amounts of emissions reduced, than for turbines that operate all year long. Also, there is no evidence

that this class of turbine has been required to install SCR or meet specific emission levels, since these peaking units emit low enough emissions to avoid BACT requirements. Therefore, Table 7-2 does not represent this category. It may be useful to define a "Small Peaking Unit" category that would be based on size, operating hours, emissions or a combination.

2. Peaking units that are large enough or operate enough to be represented by Table 7-2. These units have been required to meet more stringent requirements than Category 1. The average emission limit for this group is 6.6 ppmvd, with some units required to have SCR installed, but not all.

3. Combined cycle turbines. The permitting history also indicates that combined cycle turbines have been addressed as a separate category. Almost all of the emission limits for combined cycle turbines were 2 ppmvd, with and without duct burners.

4. Turbines burning alternative fuels were not found in any of the permits collected. Also, the performance of these turbines will vary significantly with type of fuel and turbine used. This type of turbine would best be served on a case-by-case basis.

5. Turbines operating at loads less than 50% on a regular basis and emissions during startup and shutdown. There are several ways these turbines can be handled in regulations or permits. It may be more appropriate to handle these turbine operating conditions on a case-by-case basis. Depending on how the turbines are to be operated, different emission limits would be required.