DAWSON & ASSOCIATES INC.

OPERATING EXPERIENCE WITH NOx EMISSION CONTROLS ON CANADIAN GAS TURBINE INSTALLATIONS

R. K. Dawson
Dawson and Associates Inc.

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15 Don Quichotte Blvd, Local 101, Suite 535, Ile Perrot, Qc, J7V 7X4
Phone : (514) 457-7223 Fax : (514) 457-7226 Cellular : (514) 386-7756

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EXECUTIVE SUMMARY

As part of an effort to reduce emissions of oxides of nitrogen (NOx) from stationary sources, Environment Canada lead a multi-stakeholder group of users, manufacturers, Provincial governments and other organizations, to establish a national emission guideline, N307, for land based combustion turbines. This guideline, published in December 1992, establishes minimum broad national emission targets for new stationary gas turbines.

This paper deals with a study, conducted for Environment Canada, which reviewed the last five years of operational experience by Canada's stationary gas turbine Operators, for the purpose of assessing the progress and success of current NOx control technology in achieving the guideline limits. The study reviewed 20 cogeneration, combined cycle and simple cycle installations employing water / steam injection or lean pre-mixed combustion for NOx control, to determine the effectiveness of the technology, as well as, the Operator's experience in terms of maintainability, reliability, operational impact, incremental costs and installation / retrofit considerations. Although these installations have proven that current NOx control technology is capable of achieving national guidelines, there are distinct benefits and liabilities with each type of control technology. These findings are quantified and comparisons are detailed to provide the reader with a perspective of the relative merits and effectiveness of each type of control system.

Although the data available is somewhat limited, all Operators employing current technology NOx control equipment are reporting that they are able to meet the national guidelines on NOx emissions. Those Operators using the injection of steam or water are finding that, although the limits can be met, they are unable to reduce emissions much further. Comparatively, Operators employing DLN technology combustors are indicating that preliminary results are, in some cases, substantially below guideline limits. There is only limited information available on experience with DLN systems for aeroderivative gas turbines larger than 20 MW. All of the systems were reported to yield fairly constant control of emissions over a range of ambient conditions.

Reliability and maintainability on most NOx control systems were reported to be good, with the only exceptions relating to those installations employing extensive water treatment systems. The typical problems reported were immature control systems, incorrectly sized pumps, insufficient supply of clean, soft water and in one case the requirement to re-match turbine nozzles to achieve design output. None of the installations reported significant increases in gas turbine maintenance costs, however, they have not attained sufficient experience with these systems to quantify the effects. Several of the units reviewed were reported to have suffered some form of operational problem when first commissioned, however, once the commissioning problems were resolved, nearly all units reviewed reported good reliability. Most commissioning problems were on systems employing the injection of a diluent.

EXECUTIVE SUMMARY (cont'd)

Virtually all emissions testing has been done at base load and typically only once or twice since commissioning the system. This data does reveal what these systems are capable of achieving at full load but, unfortunately, could not clarify how effective they are over the full operating range and during power transients. Typically NOx production drops off quickly at lower powers and, generally, one would expect this to be the case. Insufficient data was available to confirm reports of stable operation with changing ambient temperature and humidity levels.

Control system upsets were reported on a few DLN installations where the gas turbine was required to operate at an air/fuel staging transition point. In addition, it was reported on some of the water injection systems that the optimum injection rate to minimize NOx emissions, resulted in unacceptably high vibration levels in the gas turbine.

The true extent of the costs associated with implementing, operating and maintaining a NOx control system are still being evaluated as Operators gain more experience. However, the results of this study suggests that with current industry experience and the proper choice of systems, these costs can be minimized.

Although a significant gain in efficiency and reduction in overall maintenance costs can be realized by changing from a diluent injection system to a DLN system, it was apparent that the decision to implement a new emission control system or upgrade an existing system is often driven by corporate environmental policy rather than financial evaluation of investment payback.

Almost without exception, Operators planning new installations or upgrading existing installations with NOx control, are opting for current DLN technology. The additional costs and maintenance challenges associated with obtaining large volumes of clean, de-ionized water / steam has all but ruled out diluent injection as a means of NOx emissions control in simple and combined cycle installations. In cogeneration installations where "high quality" steam is required for the host, we are likely to see continued interest in steam injection. This preference of lean premixed combustion over other methods is not specific to size of gas turbine or type of installation. Due to the complexities involved, the cost of a DLN retrofit on an older installation, however, may be economically less attractive than purchasing a complete new DLN gas turbine.

Most of the cogeneration, combined cycle and, in fact, many pipeline compression units were reported to operate with fairly constant loads, efficiencies, fuel quality and relatively few emission control system upsets. All of the NOx control systems were reported to control emissions within a fairly constant range in spite of variations in ambient temperature or relative humidity. In consideration of these preliminary findings, the preference expressed by Operators, to have periodic emission testing performed by independent contractors, would appear to be an acceptable approach.

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1. INTRODUCTION

Ground-level ozone is caused by the atmospheric reaction of two precursor pollutants, nitrogen oxides (NOx) and volatile organic compounds (VOCs). Elevated concentrations of ground-level ozone are known to have serious effects on respiratory systems and on vegetation. NOx also contributes to the effect of sulphur dioxide in the formation of acid rain. These emissions can be transported over long distances, resulting in harmful effects in other geographical areas.

One of the sources of NOx emissions in Canada is the large and growing numbers of gas turbines that are used in stationary applications such as pipeline compression, cogeneration and electrical power generation. Most are fired by natural gas, making them one of the cleanest types of engines available for power production, however, by the nature of their operation, they are sources of NOx emissions. As such, gas turbine manufacturers have been developing various techniques for suppressing the levels of NOx produced by these units. The two principal techniques used in Canada include water injection / steam injection or dry low NOx combustors. To date, in a variety of applications across the country, it is estimated that 40 existing installations operate with some form of NOx control. At least a further 10 are being built and will also implement NOx control technology.

As part of the Canadian NOx/VOC Management Plan issued in May 1991 by the Canadian Council of Ministers of the Environment (CCME), Environment Canada has led the way in the development of a national guideline, N307 (Reference 9), to encourage reductions in the emissions of NOx while minimizing collateral emissions of other pollutants "and encouraging enhanced efficiency" from stationary gas turbines. This guideline, published in December 1992, establishes minimum broad national emission targets (Reference appendix B) for new stationary gas turbines and was arrived at through consultation with users, manufacturers, Provincial governments and other organizations.

This study was prepared for Environment Canada, to review the last five years of operational experience by Canada's stationary gas turbine Operators, for the purpose of assessing the progress and success of current NOx control technology in achieving the guideline limits.

2. SCOPE OF STUDY

The study involved interviews with and / or visits to Operators representing 20 of the existing, NOx controlled, stationary gas turbine facilities across Canada. This cross section covered a variety of gas turbine manufacturers of Industrial and Aero-derivative engine types, whose power output range varied from 3 MW to 110 MW. The gas turbines are employed in electrical power generation, cogeneration installations and pipeline gas compression. It also encompassed the two main NOx control techniques employed in Canada (11 - water/steam injection and 9 - dry low NOx combustors).

The principle areas focused on during this review were :

- Size, application and utilization of the gas turbine
- Installation type - Simple, combined, cogeneration
- Power and heat energy production / efficiency.
- NOx control technology employed and current emission levels produced.
- Methods employed in measuring the NOx emissions.
- Incremental costs to procure or retrofit the NOx control system.
- Incremental maintenance / operational costs associated with the NOx control system.
- Installation and retrofit considerations.
- Reliability and maintainability of the NOx control system.
- Changes in operation, efficiency, maintenance costs of the gas turbine with NOx control.

This information was gathered with the purpose of obtaining first hand knowledge on the operational experience and success with each type of NOx control method, as well as, the financial / operational impact these systems have had on these Operators over the last five years.

3. GAS TURBINE SIZES AND APPLICATIONS

Stationary gas turbines in Canada fall into two generic types, industrial and aero-derivatives. The industrial units have been designed for base load operation in land based applications or ship propulsion. They tend to be larger, heavier and less fuel efficient than their comparably powered aero engine turbofan derivative competitors. Differences between the two types can also include vastly different combustor configurations. The aero-derivative gas turbines employ either annular or can annular combustors within their outer casings. Many industrial units also employ one of these two configurations, but, some are designed with a separate silo type combustor which may be mounted externally on the gas turbine or stand alone beside it. The shape and size of the combustor can have a significant effect on NOx emission production due to the relationship of NOx formation with residence time and mixing of the combustion gases in the combustor (Reference 3).

The industrial units considered were base loaded and ranged in size from 4 MW to 110 MW while the aeroderivatives, also base loaded, ranged from 3 MW to 42 MW. Many of the units, of both types, in the size range less than 3 MW, do not operate under continuous base load duty. Their comparatively small size and limited operating hours results in very low tonnage emissions. As such, units less than 3 MW were not considered in this review.

All of the units studied operated on natural gas, however, a few were also capable of operating on #2 distillate fuel oil, to ensure their operation in cases of gas fuel supply interruption. The "interruptable supply" of the natural gas is sometimes negotiated in exchange for preferred rates from the supplier. Natural gas provides 2-3 % higher output and 1-2 % better efficiency (heat rate) than #2 fuel oil.

Co-generation Plants

In the typical cogeneration plant, a gas turbine is employed to drive a power turbine coupled to an electrical generator. Exhaust gases from the gas turbine pass through a heat recovery boiler to generate steam. The exhaust gas heat is often supplemented by implementing additional fuel burners in the boiler ducting. Steam generated from this boiler is used to drive a steam turbine which is coupled to a second electrical generator. To further enhance the efficiency of the plant, the exhaust steam from the steam turbine is then used by a "host" either for space heating or for processing operations. Often, the electrical power produced by the steam turbine is regulated by the demand for steam from the downstream steam host. Cogeneration units must, therefore, be sized such that electrical demand can be met even if the steam host reduces demand for steam. Otherwise, the plant may have to blow off excess steam to reduce the back pressure at the steam turbine to allow it to generate sufficient electrical power output. Depending on total plant load requirements, more than one gas turbine may be employed, as well as, multiple steam turbines and frequently additional auxiliary boilers to produce large volumes of steam required by some hosts. Other peripheral equipment such as inlet absorption chillers, cooling towers, condensing units, economizers, etc., will be employed as required by operational requirements and/or to

3. GAS TURBINE SIZES AND APPLICATIONS (cont'd)

Co-generation Plants (cont'd)

enhance cycle efficiencies. Total plant efficiencies, for these "cogeneration plants" were reported to range from 75 - 85 percent. Annual utilization were typically in the 8000 hours plus per year, during which time they operate between base and peak load ratings. A typical cogeneration plant layout is provided in Appendix A.

Combined Cycle Plants

Some of the facilities reviewed operate in a combined cycle capacity, configured as the above cogeneration facility but have no steam host. Their purpose is purely to produce electrical power as efficiently as possible from the gas turbine and steam turbine powered electrical generators. Overall plant efficiencies were reported to be in the 50 percent range. Average annual utilization for these units was also reported to be approximately 8000 hours per year at base to peak load ratings.

Gas Transmission Pipelines

Gas transmission pipelines employ gas turbines to power compressors / boosters in a simple cycle configuration. In this configuration the gas turbine merely produces exhaust gas to drive a power turbine coupled to a compressor. Since no heat is recovered from the gas turbine exhaust, efficiencies from these plants were reported to be in the 30 - 37 percent range, reflecting the efficiency of the gas turbine itself. Although the gas turbines employed in these applications were a mix of both aero-derivative and industrial, they tended to be some of the lower powered units in the study. Annual utilization on these installations was reported to be typically 5500 hours per year at base load ratings.

4. NOx CONTROL METHODS AND EFFECTIVENESS

There are two principal methods for controlling gas turbine emissions, employed in Canadian gas turbine installations : (1) injection of a diluent such as water or steam into either the burning zone of a conventional combustor or into the combustion gases at the entry to the first stage turbine nozzle; (2) design of the combustor to limit the formulation of pollutants in the burning zone by utilizing "lean premixed" combustion technology (i.e. Dry Low NOx (DLN) combustors). For the purpose of this study the first method was broken into "water injected" units and "steam injected" units.

Although the two methods can be employed simultaneously, such as DLN and steam injection, none of the installations reviewed were using more than one method. As explained below, each method has it's own technical and financial merits as well as drawbacks. However, based on reported NOx emissions produced, most of the installations reviewed, are achieving current Federal guideline limits for NOx emissions. Those that are not meeting guideline limits were in fact built prior to the implementation date of the guideline and are employing earlier interim configurations of current control technology.

The principal mechanism for NOx formation within gas turbine combustors is the oxidation of atmospheric nitrogen at the high temperatures found in the post flame region (Reference 4). The NOx created by this mechanism is dependent upon the temperature and residence time history of the reacting gases. This is a process which proceeds at exponential rates at temperatures above 1100°C (2012°F). The total concentration of NOx produced in a combustion process can thus be reduced by minimizing the local flame temperature. Hence, the concept behind injecting a diluent such as water or steam is to reduce the local flame temperature to impede the formation of NOx.

One Operator, using steam injection, reported significant changes (up to 11 ppmv) in NOx emissions with changes in ambient humidity levels. Comparatively, the changes in emission levels corresponding to ambient temperature changes were reported by a few Operators, to be quite small (typically 4 ppmv). Insufficient data was made available during the study to qualify these reports.

Water injection

Water injection has been the chosen method for installations where high pressure steam was not readily available. These installations are typically small cogeneration plants, pipeline compression or electrical peaking units. On most gas turbines the water is injected into the burning zone of the combustor via modified fuel nozzles or into the entry of the first stage turbine nozzle using a separate set of injectors. The ratio of water to fuel, depending on gas turbine loading, can range from 0.5 to 1.0 at peak loads. On larger gas turbines this requires significant volumes of very clean, de-ionized water, to prevent damaging downstream turbine components from corrosive or chemical attack by contaminants in the water. Even water supplied by city water systems requires further treatment before it can be injected.

4. NOx CONTROL METHODS AND EFFECTIVENESS (cont'd)

Water injection (cont'd)

Injection of water has been found to have limited success in reducing NOx emissions below 40 - 42 ppmv (corrected to 15 % O_2) at 100% load. The higher flow rates required can cause the CO emission levels to rise unacceptably. Instances were also reported where high vibration levels, causing engine trips, occurred when water injection rates were increased to maximum recommended levels. At maximum load conditions, typical reductions of 45 to 71 % were reported on the 3 - 20 MW sized units. None of the units over 20 MW employ water injection control (Reference table 1). Insufficient data was available at lower load conditions to make similar comparisons.

Injecting water into the combustor can provide an enhancement in the power produced by the gas turbine but this is largely mitigated by a heat rate penalty of approximately 1.8 percent in the vaporization of water droplets. As a result, most Operators reported only a minor (less than 1 percent) overall gain in power output. Insufficient data was available to assess the fuel consumption impact.

It is generally accepted by the engine manufacturers that the use of water injection can cause accelerated surface wear, cracking and deterioration of hot end components in the gas turbine. The installations in Canada have not had sufficient operational time to substantiate this concern nor establish an associated incremental increase in gas turbine maintenance cost.

The installation or retrofit of a water injection system involves the addition of manifolds, injectors (and depending on system, replacement of fuel burners), metering and control systems, pumps, filtration and deionization systems. The principal cost of such a system is often the water filtration and deionization systems. The systems ranged from simple reverse osmosis where the equipment is leased, to comprehensive in house multiple stage filtration and de-ionization systems. Depending on the supply of water and the volume required, the cost of the water filtration / treatment system, can reportedly range from $150,000 (on city supplied water) to as high as $1 million (water obtained from a nearby lake), per installation. Water consumption costs and the cost of consumables / filters used in the filtration / deionization process can also be significant, ranging as high as $35,000 / year.

A pipeline company in B.C., as one of the prime users of water injection, has found that the additional complexity of a water injection system (pumps, valves, metering system, controls, etc.) including the filtration and deionization system, can add as much as a full man year to the routine maintenance. For a couple of smaller co-gen installations in eastern Canada, using leased de-ionization systems (less than $3,000./year), there was reportedly, no significant increase in maintenance costs.

All of the Operators indicated that once initial commissioning problems were resolved, and with adequate maintenance, the systems were quite reliable.

4. NOx CONTROL METHODS AND EFFECTIVENESS (cont'd)

Steam Injection

As with water injection systems, steam is typically injected into the burning zone of the combustor or into the entry of the first stage turbine nozzle, to control the flame temperature and, hence, impede NOx formation. High pressure steam is required in order to match the compressor discharge pressures in these injection zones. On some installations steam is also injected into the compressor discharge flow or into the entry of the second stage turbine nozzle, but this is intended primarily to provide power augmentation, although it reportedly does have a small effect in reducing NOx.

Once the feed water is adequately filtered and de-ionized, it is passed through the gas turbine exhaust gas heat recovery boiler before being injected into the gas turbine combustor. Typically, duct burners are employed in the boiler to enhance the volume of steam generated. Depending on the installation, the steam produced may vary from saturated steam to a few hundred degrees of superheat. Often in a cogeneration plant, several other stand alone supplementary boilers will be employed to produce the large amounts of steam required by their hosts.

As with water, the injection of steam has been found to have limited success in reducing NOx emissions below 40 ppmv (corrected to 15 % O_2) at 100% load. Flow rates approaching the maximum recommended can cause the CO emission levels to rise unacceptably. Typical injection flow rates were reported to range from 23,000 to 30,000 lbs./hour on units from 20 - 70 MW in size. The corresponding steam injection rate to gas fuel flow varied from 1.5 lbs of steam / m^3 of gas per hour up to 3 lbs of steam / m^3 of gas per hour. All of the installations studied were governed by load requirement set points, with steam injection flow rates subsequently adjusted to minimize NOx emissions at base load. When steam is injected for power augmentation, a high volume of steam, to minimize NOx, can actually limit the gas turbines output. The steam carries 3 to 4 times more heat energy than the air it displaces, causing the fuel control to cut back to prevent the turbine overspeeding. On one particular co-gen installation this situation required a rematching of gas turbine and power turbine nozzles to compensate for the increased mass flow.

Injecting steam into the combustor can provide an enhancement in the power produced by the gas turbine (less than with water) but this is mitigated to an extent by a heat rate penalty as the steam is raised to combustion temperatures. As a result, most Operators reported only a minor overall gain in power output. Insufficient data was available to quantify associated changes in fuel consumption.

4. NOx CONTROL METHODS AND EFFECTIVENESS (cont'd)

Steam Injection (cont'd)

All of the gas turbine manufacturers indicate that the use of a water or steam diluent injection system may result in decreased combustion and turbine section component lives, due to accelerated surface wear, thermal gradient induced cracking and corrosion / mineral attack, with corresponding requirements for protective coatings and more frequent inspections. Instances of premature combustor deterioration or turbine blade failures were reported, which the Operators felt may have been related to steam or water injection, however, insufficient evidence and / or operational experience was available to be conclusive.

At maximum base load conditions, typical NOx emission reductions of 78 % were reported on units over 20 MW in size. None of the units studied, under 20 MW, employed steam injection control (Reference table 1). As NOx emissions tend to reduce very quickly with a reduction in gas turbine loading, the effect of steam injection on NOx emissions reduction would be more dramatic at lower powers. Virtually all emissions testing has been performed under full base load conditions, where the units typically operate. As such, insufficient data was available at lower load conditions to quantify the corresponding emissions levels produced.

As with water injection, the additional complexity of a steam injection system on the gas turbine, (pumps, valves, metering system, controls, etc.) including the filtration and deionization system, can add significantly to the routine maintenance. Although most operators reported no significant incremental increase, some reported requirements of a full man year of additional maintenance over normal package maintenance.

After resolving various initial commissioning problems, all of the Operators indicated that their systems were quite reliable. Some reports did, however, indicate ongoing problems with steam hose erosion requiring several replacements per year.

Dry Low NOx (DLN) Combustors

The concept used in today's Dry Low NOx combustors is referred to as "Lean Premixed Combustion". The maximum flame temperature occurs on the slightly rich side of the stoichiometric fuel/air ratio and decreases rapidly as the mixture departs from this point (Reference 4). In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel / air mixture than is required for complete combustion. This excess air reduces the overall flame temperature because a portion of the fuel must be used to heat the excess air to the reaction temperature. Because the NOx formation rate is an exponential function of temperature, a considerable reduction in NOx can be attained using this approach. Premixing the fuel and air prior to entering the combustion zone provides a uniform fuel / air mixture and helps to prevent local high temperature regions.

4. NOx CONTROL METHODS AND EFFECTIVENESS (cont'd)

Dry Low NOx (DLN) Combustors (cont'd)

DLN fuel control systems have to provide precise fuel control, maintaining a lean air / fuel mixture within a very narrow band at any load variation. To achieve the required fuel scheduling accuracy, which can be as low as ± 2% of point over the entire flow range, fuel metering is carried out by specially designed valves. As well, it is necessary to implement compensation for the valve characteristics, valve inlet pressure, discharge pressure, inlet temperature and gas fuel constituents (reference 8). To reduce cost and increase reliability, some fuel control manufacturers have changed from gas chromatography to calorimeters. Current DLN systems are available for gas fuel only, although, development is in progress for dual fuel DLN systems.

In addition to precise fuel flow control, engine manufacturers have employed various methods of fuel staging, air staging or both into defined regions of the combustors. These changes have required a complete redesign of conventional combustors to incorporate physical zones of primary, secondary, etc. combustion. The residence time of combustion gases in these lean premixed combustors also needed to be increased to ensure complete combustion of the fuel to minimize CO and unburned hydrocarbon emissions. The fuel / air ratio within the combustion zone must be carefully controlled to provide stable operation over a wide range of loads and transient conditions.

The fuel burners in a DLN system have also been modified or replaced by multiple additional burners to allow staging of the fuel flow (ignition, primary, secondary, etc.) as load demand increases. The complexity of such design changes also involve dramatic changes to the gas turbine control systems, hardware and space required to accommodate the modified combustion chamber/s and fuel manifolds.

Perhaps the greatest benefit of DLN systems is that there is no requirement for water or high pressure steam. As such, these systems are ideally suited to remote pipeline stations in simple cycle applications. Experience to date suggests that once commissioned and supplied with clean, dry fuel gas, these units do not require continued, frequent maintenance, as reported on some steam and water injection systems. A further benefit is that, compared to a steam injected system, the overall system efficiency of a cogeneration or combined cycle package is higher with DLN, making them a prime market for DLN systems. Further operating experience with these systems will be required before the longer term maintenance challenges are identified.

Much of this technology is still in the development stage with the first few prototypes entering service in the last two years. Consequently, a number of operational problems were highlighted in reports that relate to the somewhat immature state of the technology. These problems included combustion induced pressure oscillations seen as rumble and vibration, instability of the fuel control system at transition points between stages, higher incidences of cracking of external gas turbine casings / ducting and inadequate supplies of spare parts.

4. NOx CONTROL METHODS AND EFFECTIVENESS (cont'd)

Dry Low NOx (DLN) Combustors (cont'd)

On large units over 20 MW in size, at maximum load conditions, impressive reductions from 290 - 300 ppmv down to 20 -25 ppmv of NOx emissions were reported, equating to overall reductions of 92 - 93%. Similarly, on units in the 3 - 20 MW size range, reductions from 120 - 200 ppmv down to 40 - 42 ppmv were reported. This represents an overall reduction of 65 - 79 percent (Reference table 1). The reductions are based on comparisons to levels produced by uncontrolled, conventional, combustion configurations. Insufficient testing had been conducted at lower load conditions to make similar comparisons.

Although none of the Operators reported any significant maintenance requirements on their DLN systems once they were successfully commissioned, some reported control system anomalies during the commissioning phase. Insufficient operating experience has been obtained to date, to truly assess system reliability and gas turbine component durability.

Table 1 - Average NOx Emissions Reduction Compared to Conventional Uncontrolled

CONTROL METHOD	COGENERATION		COMBINED CYCLE		SIMPLE CYCLE	
	3 - 20 MW	OVER 20 MW	3 - 20 MW	OVER 20 MW	3 - 20 MW	OVER 20 MW
WATER INJECTION	45%				71%	
No. of Samples	2				4	
Controlled ppmv	41 - 45				42	
Uncontrolled ppmv	73 - 84				144	
STEAM INJECTION		78%		78%		
No. of Samples		4		1		
Controlled ppmv		38 - 42		40		
Uncontrolled ppmv		170 - 190		180		
DRY LOW NOx		92%			70%	
No. of Samples		2			7	
Controlled ppmv		20 - 25			40 - 42	
Uncontrolled ppmv		290 - 300			120 - 200	

Table 2 - Average NOx Emissions Produced by Controlled Installations

CONTROL METHOD		COGENERATION		COMBINED CYCLE		SIMPLE CYCLE	
	NOx	3 - 20 MW	OVER 20 MW	3 - 20 MW	OVER 20 MW	3 - 20 MW	OVER 20 MW
WATER INJECTION	PPMV	43				42	
(Total Pkge Output GJ)	g/GJ	92				193	
STEAM INJECTION	PPMV		40		40		
(Total Pkge Output GJ)	g/GJ		85		136		
DRY LOW NOx	PPMV		23			42	
(Total Pkge Output GJ)	g/GJ		47			229	

Table 3 - Generic Description of Sites Reviewed in the Study

CANADIAN GAS TURBINE INSTALLATIONS WITH NOx CONTROL															
TYPE	CYCLE	COMBUSTOR	NOx CONTROL METHOD	GT MW	ST MW	STEAM HEAT MW	PKGE OUTPUT MW	HRS YR	SYSTEM EFF %	NON CONTROLLED NOx ppmv	CONTROLLED NOx ppmv	FEDERAL LIMITS PPMV	FEDERAL LIMITS g/GJ	CONTROLLED NOx g/GJ OUTPUT	REDUCTION NOx TONNES/YR
CO-GENERATION AND COMBINED CYCLE															
AERO	COMBINED	ANNULAR	STIG	24.5	15	0	39.5	8,000	50	180	40	41	140/0	136	416
AERO	COGEN	ANNULAR	STIG	42	27	44	113	8,000	80	180	40 (Note 2)	47	140/40	85	1005
IND	COGEN	SILO	STIG	69	14	42	125	8,000	75	290	130 (Note 1)	47	140/40	295 (Note 1)	1862
IND	COGEN	SILO	DLN	83	31	80	194	8,000	85	290	20	49	140/40	40	4237
IND	COGEN	CAN ANNULAR	WI	3.9	0	6.85	10.75	8,000	84	84	45	56	240/40	91	90
IND	COGEN	CAN ANNULAR	WI	6	0	15	21	8,000	75	84	41	43	240/40	93	59
IND	COGEN	CAN ANNULAR	DLN	106	50	94	250	8,000	80	300	25	48	140/40	53	4130
PIPELINE GAS COMPRESSION															
AERO	SIMPLE	ANNULAR	WI	14	0	0	14	5500	37	144	42 (Note 2)	52	240/0	193	120
IND	SIMPLE	SILO	DLN	11	0	0	11	5500	31	200	42 (Note 2)	44	240/0	230	218
IND	SIMPLE	ANNULAR	DLN	10.5	0	0	10.5	5500	34	150	42 (Note 2)	48	240/0	210	142
IND	SIMPLE	ANNULAR	DLN	4	0	0	4	5500	30	120	42	42	240/0	238	44

Note 1 : Installation was built prior to guideline N307 publication and employs interim standard of NOx control technology.
Note 2 : Multiple units of the same gas turbine / installation type were reviewed and the results averaged.

5. INSTALLATION AND RETROFIT CONSIDERATIONS

Although the primary objective is to reduce the levels of NOx, CO and UHC emissions, it was imperative that the engine manufacturers also give due consideration to the ability to retrofit an existing gas turbine with NOx controls while maintaining heat rates and design point performance outputs and avoiding negative impacts on reliability, availability, maintainability and durability levels compared to the standard unit. For DLN conversions, this is an enormous challenge on engines types that have been in operation for a few decades, as there is often a multitude of configurations and modification standards that must be considered. Some of the manufacturers have stated that the magnitude of the hardware retrofit required for DLN on older units, along with the loss of production likely to be encountered, would make retrofit less financially practical than a complete new unit installation. At least one of the manufacturers is considering offering exchange package proposals in anticipation of the cost and complexity of retrofitting older units. Further, the impact on heat rates and overall performance is anticipated to be somewhat of a trial and error with the various combinations of hardware that could exist within one type of unit.

Many NOx control systems reviewed in this study were installed as part of a new gas turbine package. In addition, very few packages have accumulated sufficient operating hours to have reached a recommended heavy maintenance interval. As such, it is very difficult for any Operator interviewed to quantify the relative changes, if any, to performance, reliability, availability, etc. Further operating experience will be required on a larger sample of installations before a meaningful assessment can be done.

The degree of difficulty encountered, to retrofit a system employing the injection of steam or water, is very dependent on the supply source of the feedwater. If substantial filtration and deionization is required, there is a corresponding increase in the complexity of the water treatment facility and the amount of controls, maintenance, space and investment required. Compatibility with existing hardware, especially on the gas turbine was not raised as an issue. Not surprisingly, the most common advise provided by Operators was that the primary consideration in retrofitting was to ensure a plentiful supply of clean, soft water. Some of these Operators had incurred increased maintenance costs in the form of additional manhours to service the water treatment system and in the cost of consumables such as filters and salt.

Other considerations raised with respect to water / steam injection is the requirement for protective coatings on some gas path components and / or design changes to components to withstand the thermal shock and accelerated wear associated with the injection of a diluent. Although no conclusive evidence was provided in the study that the use of a diluent will accelerate the deterioration of a gas turbines hot end components, this is generally accepted as inevitable, by the industry.

5. INSTALLATION AND RETROFIT CONSIDERATIONS (cont'd)

All of the DLN units studied, have been installed as part of a new package installation. Retrofit packages have only recently been made available from some of the engine manufacturers. These manufacturers are claiming that compatibility with the rest of the gas turbine has been carefully considered, but each installation must be evaluated independently. Often the retrofit of DLN combustion hardware requires extensive modifications to the combustion section / module of the engine and the complete replacement of the fuel control systems. For several installations this requires a larger clearance envelope around the gas turbine and within the enclosure, as in the case of a shorter, larger diameter DLN silo combustor or the conversion from a conventional annular combustor to a DLN radial pot combustor configuration. Further, staging of the fuel and/or air into a DLN combustor often requires multiple fuel manifolds or air ducting with associated piping, valves and sophisticated controls. The fuel control valves are replaced with units having very fast reaction times in order to control flame stability in these lean ratio combustors.

Insufficient data was available to determine if heat rates and design point performance outputs were significantly affected by the implementation of a NOx control method. Data of the necessary precision, to verify this, would only be available from the engine manufacturers. Given the developmental stage of the technology, the manufacturers are unable to supply concise data on these parameters, but infer that these operational parameters will not be significantly affected.

A few operators chose to install dual fuel capability (natural gas and #2 distillate fuel oil) to allow them to deal with interruptable gas supply situations. In most cases the interruptable supply was self imposed in order to take advantage of lower natural gas supply prices. Even with dual fuel capability the vast majority of operation was on natural gas. When retrofitting with NOx controls the dual fuel capability needs to be carefully considered with respect to permitting requirements.

6. INCREMENTAL OPERATIONAL COSTS

Many of the NOx controlled gas turbine installations in Canada have not accumulated sufficient Operating time to have reached a major overhaul life. Without experiencing at least a few overhaul cycles it is impossible to assess the longer term impact of NOx controls on gas turbine maintenance costs relative to those of a conventional configuration. Accelerated surface wear, cracking and deterioration of hot end components due to the injection of steam or water is generally expected by the industry and the gas turbine manufacturers, however, no conclusive case studies were reported during this study.

It was initially hoped that an evaluation of changes in heat rates and fuel consumption relating to NOx controls, could be included in this study but insufficient data was available to make any quantifiable comparisons.

Some Operators reported incurring identifiable maintenance costs associated with servicing their water treatment facilities. These costs were reported to range as high as a full man-year of labour and as high as $15,000 in parts. Several Operators employing water or steam injection also reported significant one time costs associated with commissioning new control systems. These costs were generally associated with lost production due to immature control systems, incorrectly sized pumps, vibration induced trips from high injection rates and water supply problems.

On a typical cogeneration installation employing steam injection, it was calculated, by the author, that the cost of heating feedwater to superheated steam, for injection, was approximately $.0055 per pound of steam. This value when applied to a flow rate of 24,000 lb./hour for an annual utilization of 8000 hours, equates to more than $1 million dollars operating cost. Assuming this steam could have been otherwise sold to a host, used for space heating or generating electricity via a steam turbine, it represents a very significant recurring operational cost.

None of the DLN installations reported any noticeable increase in routine maintenance costs, however, some reported increased tendencies for ducting and engine casing cracks which was being investigated to determine the cause. Some of the installations were also suffering control system instability at fuel or air staging transition points. The instability on one unit was more pronounced as the gas turbine was required to operate below full power at a level corresponding to a staging transition point. The result was continuing gas turbine trips and lost production.

7. COSTS PER TONNE OF NOx REDUCTION

In determining the costs per tonne of NOx reduction, several variables had to be considered when comparing one installation to another. These variables included such items as: operating profile by day and by season, annual utilization, LHV of the fuel, insufficient information on fuel flows at various loads, plant configurations, plant efficiencies, emission levels by season / load / etc. Further, retrofit costs can vary by multiples depending on the age and configuration of the existing equipment. As such, a number of assumptions were required on a plant by plant basis in order to make comparisons between units meaningful.

For the purpose of comparing installations, the following basic assumptions were made :

- The LHV of natural gas = 37.7 GJ/1000 m3
- When operating on natural gas 1 ISO ppmv = 1.70 grams of NOx / GJ input.
- All fuel burnt in the boiler auxiliary duct burners was treated as if it had been burned in the gas turbine.
- NOx Control System procurement / retrofit costs were amortized over a 20 year period at 6% interest rate to obtain present values.
- Retrofit costs were assumed to equal the incremental costs between new standard combustion configuration and DLN configuration.
- Cost of producing superheated steam for injection was assumed to be $.0055/lb.
- It was assumed that the cost of generating steam was an added cost, in that the steam could have been otherwise sold or not produced at all.
- The benefit of power augmentation from the injection of a diluent was considered on installations where there was sufficient data to quantify this aspect.
- Due to insufficient operating experience and conclusive data, the incremental gas turbine maintenance costs were not considered in this evaluation.
- All "cogeneration" and "combined cycle" installations were reported to operate 8000 hours or more per year. For this comparison 8000 hours per year was assumed.
- All "simple cycle" installations were assumed to operate 5500 hours per year.
- Incremental maintenance costs and water treatment / consumption costs as reported by each Operator were assumed typical annual recurring costs.
- NOx emissions testing data, even if limited to initial commissioning, was assumed to be representative of an average annual rate at maximum load.

Although the margin of error in this approach could be quite significant it does allow a relative comparison between installation types and gas turbine sizes. As such, the results, shown in table 4, should be taken as best approximations from the limited data that was made available during the course of this study.

7. COSTS PER TONNE OF NOx REDUCTION (cont'd)

The "cost / year" shown in table 4 is the summation of amortized procurement / retrofit costs of the necessary installation and gas generator equipment, incremental system maintenance costs and additional operational costs based upon the above assumptions. The maintenance costs included estimates of the additional labour and material costs as reported by the Operators. Operating costs included water consumption / filtration / deionization and, where STIG was employed, the cost of fuel to generate the steam. If power augmentation figures were available, the operating costs were offset by this additional revenue. These costs were averaged for different installation types and size ranges as identified in the table. Similarly, the "$ / Tonne" figures are the annual costs for each installation divided by the calculated reduction in NOx reduction in tonnes / year for that installation. The "$ / Tonne" values derived for each type of installation and size range, shown in table 4, were averaged.

Table 4 - Average Costs of NOx Control Systems

CONTROL METHOD		COGENERATION		COMBINED CYCLE		SIMPLE CYCLE	
	NOx	3 - 20 MW	OVER 20 MW	3 - 20 MW	OVER 20 MW	3 - 20 MW	OVER 20 MW
WATER INJECTION	$ / TONNE	$492	NOTE 1	NOTE 1	NOTE 1	$2,850	NOTE 1
	COST / YR	$29,600.00				$340,000	
STEAM INJECTION	$ / TONNE	NOTE 1	$847	NOTE 1	$1,730	NOTE 1	NOTE 1
	COST / YR		$851,000		$721,000		
DRY LOW NOx	$ / TONNE	NOTE 1	$77	NOTE 1	NOTE 1	$450	$1,020 NOTE 2
	COST / YR		$321,000			$73,000	$400,000 NOTE 2

Note 1 : Units in this category are not commonly used in Canada.
Note 2 : Recent installations in this category. Values estimated.

In general, the DLN systems are reported to be the cheapest to install and operate over the longer term and are the most effective at reducing NOx emissions (Reference Table 1) therefore, reflecting the lowest cost per tonne of NOx emission reduction.

Most of the NOx control systems reviewed in this study were installed as part of a new gas turbine package. Therefore the retrofit costs were based upon budgetary estimates from the manufacturers and included all of the on engine and off engine hardware / changes required. It was reported by the manufacturers that the actual conversion costs can vary dramatically between units depending on their age and current configuration. In some cases it may actually be cheaper to purchase new DLN units rather than convert existing installations.

7. COSTS PER TONNE OF NOx REDUCTION (cont'd)

Although water and steam injection tend to be the cheapest method in terms of procurement / retrofit, they also are reported to have much higher recurring operational and maintenance costs. Water treatment and consumption costs are primary drivers, but, when one includes the fuel costs in generating the volumes of superheated steam required for injection, these costs are quickly dwarfed. In virtually all STIG systems reviewed, the steam required for injection was an additional expense in that additional boilers could have been shutdown if this injected steam could have been diverted to the steam host. Only in one cogeneration installation was there an occasional requirement to blow off excess steam not needed by the host to reduce the back pressure and allow the steam turbine to produce the necessary level of electric power.

Another major factor that will affect these costs over the longer term is the changes in gas turbine maintenance costs that may be proven to be attributable to the type of control method employed. This information will require many more years of operating experience and close monitoring of relative costs to be assessed adequately.

8. MONITORING OF NOx EMISSIONS

Very few of the installations reported that they performed their own emissions testing. Instead they have chosen to subcontract the testing to specialist service companies. Several Operators, especially those operating only a few gas turbines, felt that the cost of owning reliable, good quality test equipment, along with, personnel training, calibration gases, etc., could not be justified. They also recognize that the determination of accurate readings requires the establishment of repeatable test protocol, bias correction, correction of results to ISO conditions and 15% O_2 content. Most felt this was better left to knowledgeable experts.

Only one Operator had chosen continuous emissions monitoring equipment and reported reliability problems with the equipment and significant costs for calibration and zero gases (up to $3000. per month). They were also testing with a portable analyzer and indicated that, with their gas turbines operating continuously at base load, the emission levels recorded are, on average, fairly constant. Changes due to ambient air relative humidity is reported by one Operator to cause changes in NOx emission levels of up to 11 ppmv. Comparatively, changes in ambient from summer to winter were reported by a few Operators to average typically 4 ppmv. These variations were reported by a very limited number of Operators and without verification by outside specialists, can not be taken as representative for all installations.

There are still relatively few NOx controlled installations in Canada and many are only 2 to 4 years old. Under the current Federal / Provincial guidelines, these installations are required to test every one or two years, and as such, the amount of emissions testing conducted to date is somewhat limited. Those Operators who are subcontracting their testing are typically following the frequency suggested in their respective provincial guidelines. Other Operators who have chosen to perform their own testing with portable analyzers, are not testing more often than quarterly. Several of the most recent installations are equipped with predictive emission monitoring systems, however, the commissioning of these installations was still in process and results were not available for inclusion in this study. In general, most Operators are unaware of the actual emission levels they are producing, and in some cases, the overall efficiency and / or changes in efficiency of their plants. This information must be known with a degree of confidence before a determination can be made of emissions relative to guideline limits.

Most testing conducted to date is on new installations during initial commissioning, however, the data reported indicates that current technology of either method is capable of achieving published guidelines with the gas turbine operating at full load. Testing at reduced power settings is extremely limited and, as such, this study was unable to derive meaningful information from the limited data.

In conjunction with striving to achieve published Federal / Provincial guidelines, several Operators reported they are also working to meet additional corporate environmental objectives with respect to emissions. In some cases this meant the application of the guidelines to older units and retrofit upgrade plans.

8. MONITORING OF NOx EMISSIONS (cont'd)

A few Operators who are not currently using their existing NOx control systems, reported that Provincial regulations with respect to "ground impingement levels" of NOx within their installation perimeters, allowed them permits to operate without heeding the guideline limits of NOx emissions in the exhaust. This is an area of potential conflict that needs to be addressed by the affected regulatory authorities.

The opinions expressed by participants in this study suggest that most Operators believe that the frequency of testing suggested in current regulatory guidelines is sufficient, given their relatively stable operating patterns, plant efficiencies and fuel quality. In this regard the preferred, and most economical, method of monitoring emission levels, is seen to be periodic testing by third party contractors.

9. SUMMARY AND RECOMMENDATIONS

Although the data available is somewhat limited, all Operators employing current technology NOx control equipment are reporting that they are able to meet the national guidelines on NOx emissions. Those Operators using the injection of steam or water are finding that, although the limits can be met, they are unable to reduce emissions much further. Comparatively, Operators employing DLN technology combustors are indicating that preliminary results are, in some cases, substantially below guideline limits. All of the systems were reported to yield fairly constant control of emissions over a range of ambient conditions.

Reliability and maintainability on most NOx control systems was reported to be good, with the only exceptions relating to those installations employing extensive water treatment systems. The typical problems reported were immature control systems, incorrectly sized pumps, insufficient supply of clean, soft water and in one case the requirement to re-match turbine nozzles to achieve design output. None of the installations reported significant increases in gas turbine maintenance costs, however, they have not attained sufficient experience with these systems to quantify the effects. Several of the units reviewed were reported to have suffered some form of operational problem when first commissioned, however, once the commissioning problems were resolved, nearly all units reviewed reported good reliability. Most commissioning problems were on systems employing the injection of a diluent.

Virtually all emissions testing has been done at base load and typically only once or twice since commissioning the system. This data does reveal what these systems are capable of achieving at full load but, unfortunately, could not clarify how effective they are over the full operating range and during transients nor how they behave under changing ambient temperature and humidity levels. Typically NOx production drops off quickly at lower powers and, generally, one would expect this to be the case.

Control system upsets were reported on a few DLN installations where the gas turbine was required to operate at an air/fuel staging transition point. In addition, it was reported on some of the water injection systems that the optimum injection rate to minimize NOx emissions, resulted in unacceptably high vibration levels in the gas turbine.

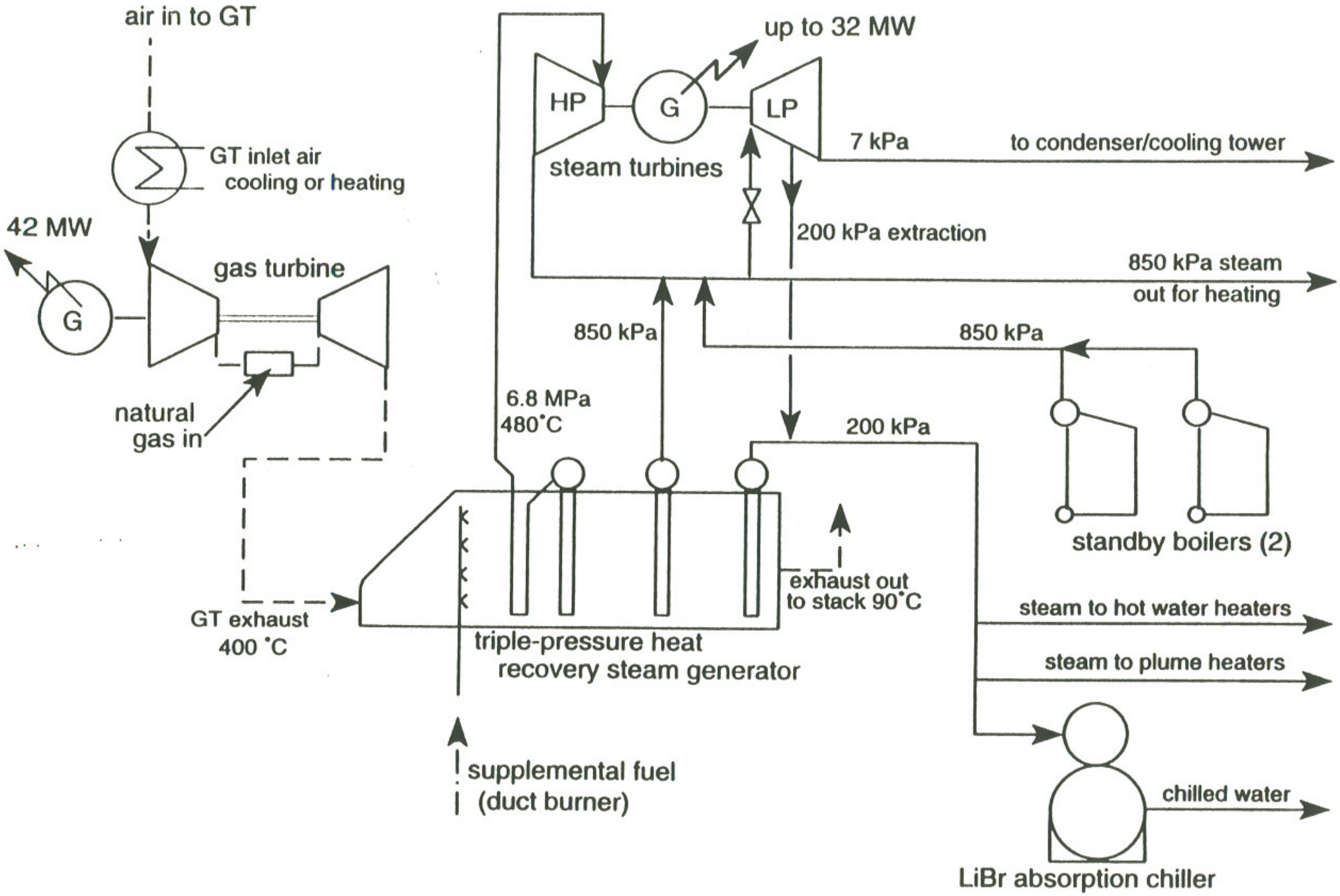
The true extent of the costs associated with implementing, operating and maintaining a NOx control system are still being evaluated as Operators gain more experience. However, the results of this study suggests that with current industry experience and the proper choice of systems, these costs can be minimized.

Although a significant gain in efficiency and reduction in overall maintenance costs can be realized by changing from a diluent injection system to a DLN system, it was apparent that the decision to implement a new emission control system or upgrade an existing system is often driven by corporate environmental policy rather than financial evaluation of investment payback.

9. SUMMARY AND RECOMMENDATIONS (cont'd)

Almost without exception, Operators planning new installations or upgrading existing installations with NOx control, are opting for current DLN technology. The additional costs and maintenance challenges associated with obtaining large volumes of clean, de-ionized water / steam has all but ruled out diluent injection as a means of NOx emissions control in simple and combined cycle installations. In cogeneration installations where "high quality" steam is required for the host, we are likely to see continued interest in steam injection. This preference of lean premixed combustion over other methods is not specific to size of gas turbine or type of installation. Due to the complexities involved, the cost of a DLN retrofit on an older installation, however, may be economically less attractive than purchasing a complete new DLN gas turbine.

Most of the cogeneration, combined cycle and, in fact, many pipeline compression units were reported to operate with fairly constant loads, efficiencies, fuel quality and relatively few emission control system upsets. All of the NOx control systems were reported to control emissions within a fairly constant range in spite of variations in ambient temperature or relative humidity. In consideration of these preliminary findings, the preference expressed by Operators, to have periodic emission testing performed by independant contractors, would appear to be an acceptable approach.



SAMPLE COGENERATION PLANT LAYOUT

11. APPENDIX B - NATIONAL GUIDELINE N307 SUMMARY OF LIMITS (Ref. 9)

11.1 Emissions of Oxides of Nitrogen

The emission targets for various types of combustion turbines are determined by calculation of the allowable mass of NOx (grams) per unit output of shaft or electrical energy (Gigajoules), as well as, an allowance for an additional quantity of NOx emitted if useful energy is demonstrated to be recovered from the facility's exhaust thermal energy during normal operation. Allowable emissions over the relevant time period equal :

(POWER OUTPUT X A) + (HEAT OUTPUT X B) = grams of NO_2 equivalent

Where :

- Power Output is the total electricity and shaft power energy production expressed in Gigajoules (3.6 GJ per MW-hour).
- Heat Output is the total useful heat energy recovered from the combustion turbine facility.
- "A" and "B" are the allowable emission rates, expressed in grams per Gigajoule, for the facility's power and heat recovery components respectively, as summarized below.

POWER OUTPUT ALLOWANCE "A" (g/GJ)

NON-PEAKING TURBINES	Natural Gas	Liquid Fuel
Less than 3 MW	500	1250
3 - 20 MW	240	460
Over 20 MW	140	380
PEAKING TURBINES		
Less than 3 MW	Exempt	Exempt
Over 3 MW	280	530

Note :

1. The value of "A" has been set at 500 g/GJ for solid-derived fuels which recognizes that the competing alternative technology option is a conventional coal-burning steam electric power plant.

11. APPENDIX B-NATIONAL GUIDELINE N307 SUMMARY OF LIMITS (cont'd)

HEAT RECOVERY ALLOWANCE "B" (g/GJ)

For all Units :	Natural Gas	40
	Liquid	60
	Solid-Derived	120

The Heat Recovery Allowance is a NOx emission allowance for energy recovered from turbine exhaust gases as heat. The allowance corresponds to the emissions savings which result from not serving a heating or cooling load by burning additional fuel in an industrial boiler, but by recuperating heat during normal operation from combustion turbine exhaust gases and other sources of 'waste' heat such as condensate.

Definition of Terms

Combustion Turbine : A combustion turbine is an engine which operates according to the Brayton thermodynamic cycle, in which fuel is burned and the products of combustion at a high temperature are allowed to expand through a rotating power turbine thus producing a net amount of motive power.

Peaking Combustion Turbine : A peaking combustion turbine is a unit which is ordinarily used to supply electric or motive power at periods of high demand or during unforeseen outages. Such a unit will not usually operate more than 7500 hours in any year period and, in those years, a total of no more than 3000 hours during the months of May, June, July, August and September.

Combustion Turbine Facility : A combustion turbine facility includes the combustion turbine, the steam turbine (if applicable), the fuel handling equipment, related pollution control and flue gas handling equipment, and equipment required to directly recover energy from the exhaust gases. For simplification of thermal energy measurement, it excludes the downstream heating, cooling and industrial processes which utilize thermal energy recovered from the facility.

Power Rating : The power rating of a combustion turbine unit is the normal maximum continuous rating , in Megawatts, at ISO conditions as provided by the manufacturer.

ISO Conditions : International Standards Organization conditions refer to a reference state of 288 degrees K ambient temperature, 60 percent relative humidity and 101.3 kilopascals barometric pressure.

12. APPENDIX C - SAMPLE NOx EMISSION CALCULATIONS

The following sample calculations relate to a typical cogeneration combustion turbine facility which includes a combustion turbine / generator, an exhaust heat recovery boiler and a steam turbine / generator. Additional duct burners are used for supplementary heat. Steam is supplied to a host for space heating.

Combustion turbine / generator output :	42 MW (peak load) 38 MW (base load)
Natural gas fuel consumption:	14,000 m^3/hr (peak load - includes duct burners) = 527.8 GJ/hr 11,500 m^3/hr (base load - includes duct burners) = 401.2 GJ/hr
Steam turbine / generator output :	up to 32 MW
Superheated Steam to host :	up to 160,000 lbs / hr.
Steam injection into combustion turbine :	up to 24,000 lbs / hr at peak load.
NOx emissions output :	40 ppmv (peak load with STIG)
Combustion turbine efficiency :	40 %
Overall package efficiency :	80 % (includes losses due to inlet absorption chillers, condensing units, cooling towers, etc.)
Annual utilization :	8000 hours

Typical loading :
7:00 a.m.- 11:00 p.m. "peak load" (69 MW electrical only)
7:00 a.m.- 11:00 p.m. "peak load" (44 MW heat load)
11:00 p.m.- 7:00 a.m. "base load" (52 MW electrical only)
11:00 p.m.- 7:00 a.m. "base load" (33 MW heat load)

Assumptions

- The LHV of natural gas = 37.7 GJ/1000 m3
- When operating on natural gas 1 ISO ppmv = 1.70 grams of NOx / GJ input.
- All fuel burnt in the boiler auxiliary duct burners was treated as if it had been burned in the gas turbine.

NOx Emission Limit at "Peak Load"

NOx emissions limit = (C * E) / D
where,
C = output allowance per appendix B
E = efficiency factor (thermal efficiency (%) of combustion turbine and heat recovery / 100)
D = fuel constant (1.70 g NO_2 per GJ of heat input per ppmv @ 15% O_2 for natural gas fuel)

C = [(69/113) * 140 + (44/113) * 40] = 101.1 g/GJ output
E = 0.80
D = 1.7

Emission Limit = (101.1 * 0.80) / 1.7 = 47 ppmv @ 15 % O_2

13. REFERENCES

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