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OPERATIONAL EXPERIENCE WITH ONCE THROUGH STEAM GENERATORS IN GAS TURBINE COMBINED CYCLE / COGENERATION CYCLES

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ABSTRACT

Once Through Steam Generators (OTSG) have been used successfully in combined cycle, cogeneration and gas turbine steam injection applications for all gas turbine sizes and steam cycles. The gas turbine selection is a significant factor affecting the complexity of the OTSG design and operation.

This paper will address four areas in which the OTSG design can be affected – specifically gas turbine emission reduction, gas turbine noise reduction, gas turbine exhaust flow profile correction and gas turbine power augmentation.

Gas turbine emission reduction requires the introduction of flue gas cleaning equipment such as selective catalytic reduction systems (SCR) or carbon monoxide catalyst (CO). Gas turbine noise reduction may require a combination of acoustic baffles placed in the tube bank, silencer splitters placed in the OTSG ducting and/or acoustic shrouds placed around the OTSG ducting. The gas turbine exhaust flow profile can be quite turbulent leading to duct failures, poor duct burner performance and unacceptable OTSG performance. Correction of this exhaust flow maldistribution is required. Finally, the recent trend to increase the power output of gas turbines through power augmentation and its effect on the OSTG design will be analyzed. Operational experience and field results for the above areas will be presented.

BIOGRAPHY

Jim McArthur is currently Vice President, Technology at Innovative Steam Technologies (IST) located in Cambridge, Ontario, Canada. IST designs and manufactures once through steam generators (OTSG's) for the international power and process markets. During his years at IST, Jim has held various positions in the Proposals and Engineering departments. In his current position Jim manages the Engineering Services, Field Service and Research and Development departments. Prior to working at IST, Jim worked at Foster Wheeler Limited, designing heat recovery steam generators (HRSG's).

CHARACTERISTICS OF ONCE THROUGH STEAM GENERATORS

The once-through steam generator, in its simplest form, is a continuous tube in which preheating, evaporation, and superheating of the working fluid takes place consecutively as indicated in Figure #1.

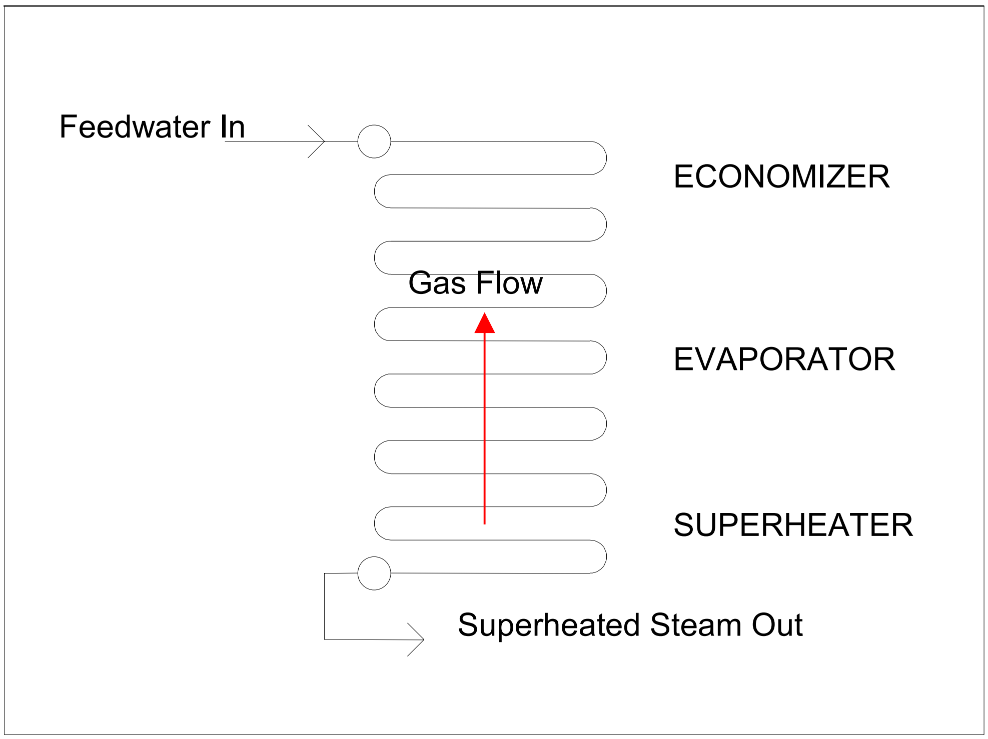

Figure #1 – Once through steam generator (OTSG)

In practice, of course, many tubes are mounted in parallel and are joined by headers thus providing a common inlet for feedwater and a common outlet for steam. Water is forced through the tubes by a boiler feedwater pump, entering the OTSG at the "cold" end. The water changes phase to steam midway along the circuit and exits as superheated steam at the "hot" or bottom of the unit. Gas flow is in the opposite direction to that of the water flow (counter current flow). The highest temperature gas comes into contact with water that has already been turned to steam. This makes it possible to provide superheated steam.

The advantages inherent in the once-through concept can be summarised as follows:

1. Minimum volume, weight, and complexity.
2. Inherently safe as the water volume is minimized by using only small diameter tubing.
3. Temperature or pressure control are easily achieved with only feedwater flow rate regulation.
4. Complete elimination of all by-pass stack and diverter valve requirements while still allowing full dry run capability.
5. Complete modular design with inherently lower installation time and cost.
6. Operational benefits such as improved off design (turn down) efficiency

The once-through steam generator achieves dissolved and suspended solids separation external to the steam generator by pre-treatment of the OTSG feedwater. Any solids remaining in the feedwater, either suspended or dissolved, can form deposits on the OTSG tubing and/or be carried over to the gas turbine. Dissolved oxygen control is not a critical issue for the IST OTSG, which is made of alloy tubing.

OTSG's can be supplied in both horizontal tube/vertical gas flow arrangements (Figure #2 and #3) as well as vertical tube/horizontal gas flow arrangements (Figure #4 and #5) to match customer requirements.

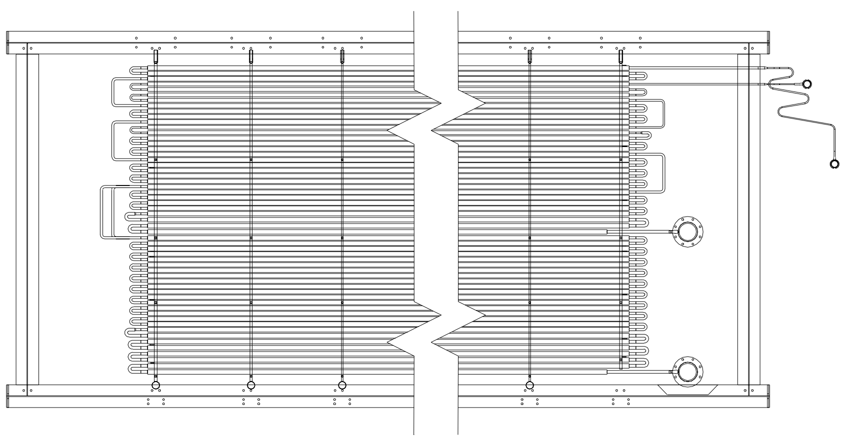

Figure #2 – Horizontal Tube / Vertical Gas Flow Arrangement

Figure #3 – Horizontal Tube / Vertical Gas Flow Arrangement
LM6000 Gas Turbine

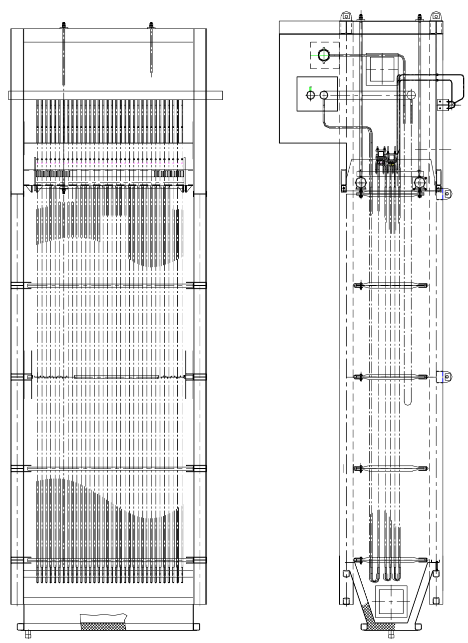

Figure #4 – Vertical Tube/Horizontal Gas Flow Arrangement

Figure #5 – Vertical Tube/Horizontal Gas Flow Arrangement
Frame 7FA Gas Turbine

Innovative Steam Technologies's OTSGs have been used for combined cycle, cogeneration and gas turbine steam injection applications. With almost 100 units supplied to date internationally, a great deal of experience has been gained in the application of the OTSG to various gas turbines.

Specific experience regarding the following areas will be discussed in detail:

a) Gas Turbine Emission Reduction
b) Gas Turbine Noise Reduction
c) Gas Turbine Exhaust Flow Profile Correction
d) Gas Turbine Power Augmentation

GAS TURBINE EMISSION REDUCTION

Nitrous oxides, principally NO and NO_2, result from high temperature combustion such as in the combustion of fossil fuels in gas turbines. Emission of these nitrous oxides (commonly referred to as NO_x) into the atmosphere have negative effects such as contributing to the formation of acid rain and smog. Under certain conditions, NO_x can react to form ozone. All of these results of NO_x can irritate the nose and throat and can also impair lung function. Gas turbine technology has been successful in reducing NO_x emissions from levels as high as 150 ppmvd (when operating on natural gas) to levels below 25 ppmvd through steam injection or dry low NO_x combustion. With NO_x emission limits commonly around 2 ppmvd in many American locations, further processes such as the selective catalytic reduction process have been developed to reduce these emissions in combined cycle power plants.

Selective Catalytic Reduction (SCR) Process

The SCR NO_x removal system (also referred to as $DeNO_x$) is a dry process in which ammonia (NH_3) is used as a reducing agent, and the NO_x contained in the flue gas is decomposed into harmless N_2 and H_2O. See Figure #6 below for a diagram of the NO_x removal process reactions.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$$
$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$$

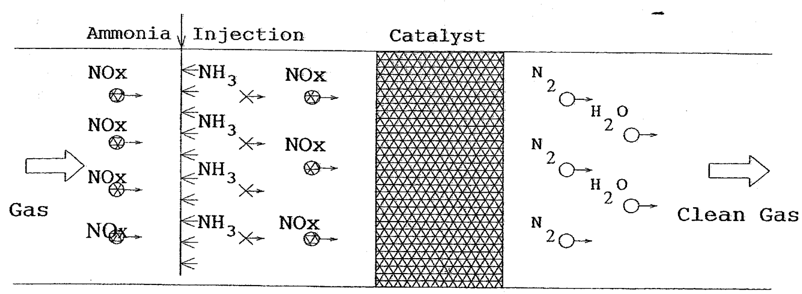

Figure #6 – NO_x Removal Process

Ammonia (NH_3) is injected into the flue gas upstream of the SCR catalyst, through a special injection grid to assure even distribution and mixing within the flue gas. The flue gas then passes through the catalyst layer.

SCR Location

The SCR must be located in the appropriate gas temperature zone for maximum efficiency. A typical efficiency vs. gas temperature curve is shown in Figure #7. Typical medium temperature SCR catalyst maximum continuous operating temperature is 800°F with short temperature excursions up to approximately 870°F. Although the catalyst can operate at temperatures up to 870°F it is not recommended that the catalyst temperature exceed 800°F during continuous operation in order to maximize efficiency and catalyst life.

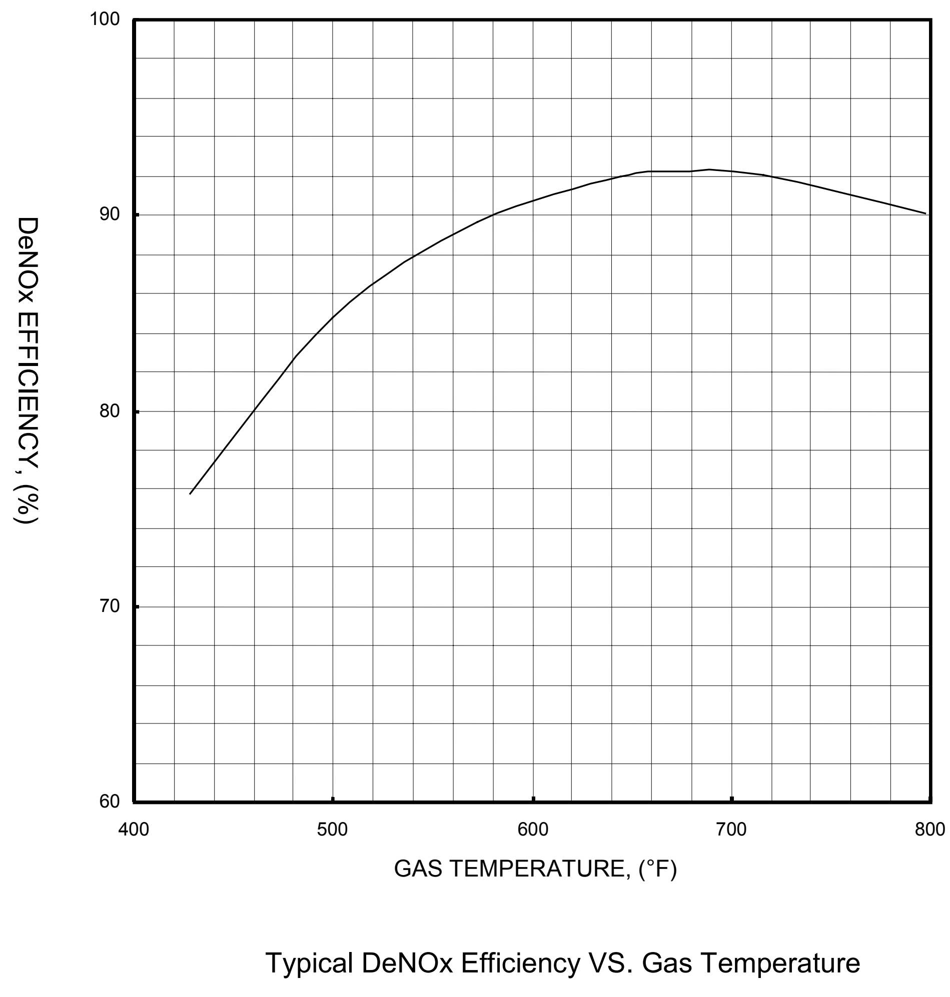

Figure #7 – DeNOx Efficiency vs. Gas Temperature Curve

The flexibility of the OTSG allows for optimum placement of the SCR surface in the pressure parts in either the evaporator or superheater section of the OTSG as required for optimum operation of the SCR. As intermediate headers are not used, the tubes are simply jumpered over the SCR surface as shown in Figure #8.

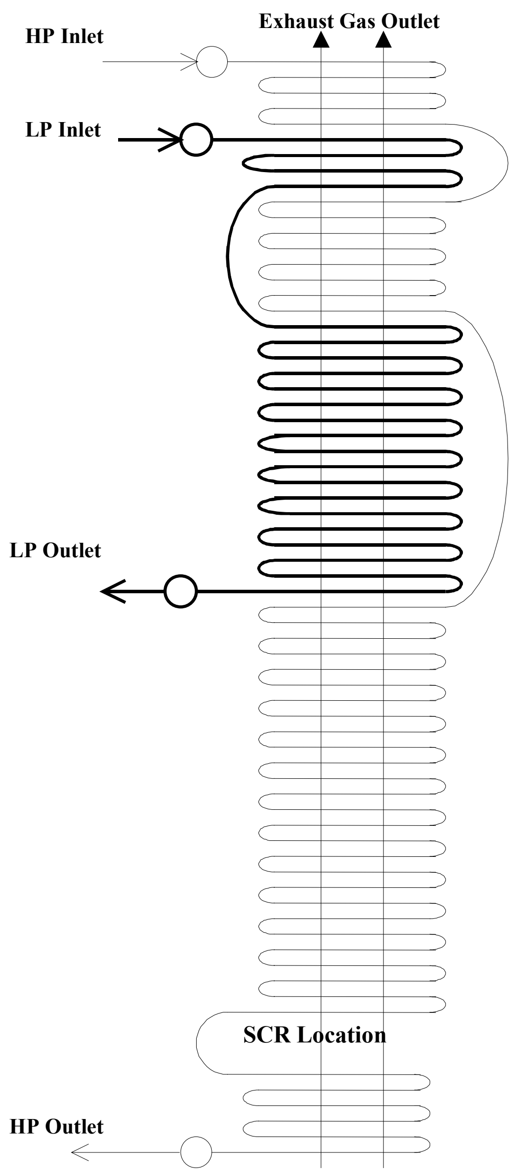

Figure #8 – SCR Catalyst Location in OTSG Tube Bundle

SCR System Components

The SCR DeNOx system is comprised of subsystems such as the ammonia injection system, air supply system and the SCR reactor.

Ammonia Injection System

Ammonia Supply System

Ammonia is supplied to the ammonia flow control unit (AFCU). The ammonia flows into the vaporizer and is diluted with air to achieve an air/ammonia volume ratio of approximately 19:1, in order to avoid a possible explosion of the air/ammonia mixture

Ammonia Injection Grid

The ammonia injection grid (AIG) is installed upstream of the SCR catalyst. The AIG consists of injection pipes and spray nozzles. Ammonia/air mixture injection is adjusted in accordance with NO_x concentration distribution through multiple holes. The design of the AIG is crucial to ensure proper operation of the SCR system. Flow modeling is required to ensure a uniform distribution of ammonia/flue gas mixture to the SCR catalyst.

Electric Heater and Aqueous Ammonia Vaporizer

An electric heater is equipped to heat up the dilution air. Uniform air flow (vaporized aqueous ammonia and dilution air) is achieved with a perforated plate.

Air Supply System

An ammonia dilution air fan is used as the supply source for dilution air. Mixing of the ammonia with air is achieved in the vaporizer and piping, and introduced to the ammonia distribution manifold. The ammonia/air injection system consists of supply headers, grid of injection pipes and nozzles.

Each supply header is equipped with a manual throttling valve and flow orifice for obtaining a uniform distribution of the ammonia/flue gas mixture to the injection pipe grid. The manual throttling valves are set up by using the NH_3 and/or NO_x values obtained from sampling connections traversing the flue gas duct.

SCR Reactor

The SCR reactor is located in the flue gas duct downstream of the gas turbine. The SCR reactor uses a fixed bed, parallel passage type, vertical reactor. The reactor is a bottom supported steel structure. The reactor consists of an internally insulated exterior casing and internal catalyst support structure designed to sustain internal pressure, earthquake loading, wind gust loading, catalyst loading and thermal stress. Necessary seals are installed at the bottom, sides and top of the catalyst layer in order to prevent untreated gas bypassing.

Catalyst elements can consist of support plates integrally coated with active catalyst on a titanium dioxide base. Flue gas flow is parallel to the catalyst elements to minimize pressure drop. Multiple plate elements are assembled into a catalyst unit, with catalyst units modularized into catalyst blocks for ease of shipment and installation. A typical catalyst unit assembly is shown in Figure #9.

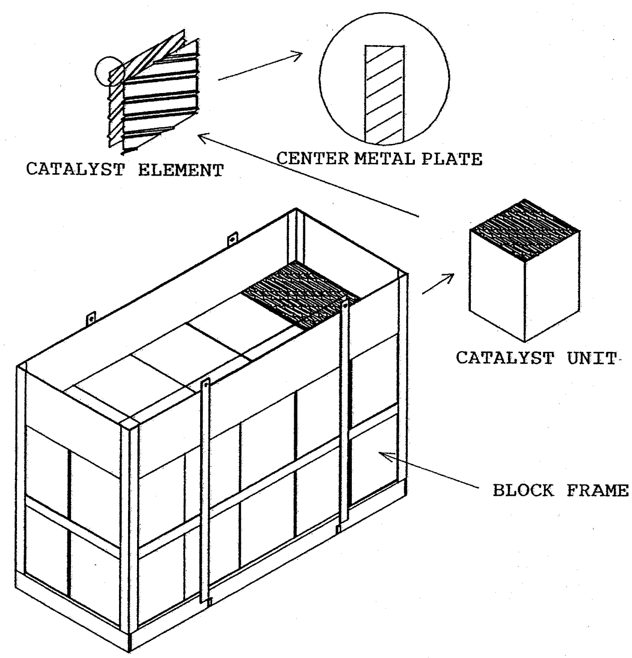

Figure #9 – SCR Reactor and Catalyst Units

The backpressure addition on the gas turbine can vary from 3 to 3-1/2 inches water column with the insertion of the SCR reactor resulting in a decrease in efficiency. CO catalysts can contribute 1.5 to 2.5 inches water column.

Corrosive Environment

The environments resulting from SCR operation can be quite severe. There are many sources of contaminants in SCR applications, which can cause premature corrosion of pressure part surfaces and ducting components. As described above, ammonia is injected into the exhaust gas as necessary to remove the NO_x compounds. This ammonia can combine with sulfur in the exhaust gas to form ammonium sulphate and/or ammonium bisulphate. The type of contaminant formed depends on the amounts of ammonia and sulphur present in the exhaust gas along with the local gas temperatures. In most applications operating on natural gas with ammonia slip levels of 10 ppm or less, ammonium sulphate is the most common contaminant. In oil fired applications with increased levels of sulphur, ammonium bisulphate can precipitate onto the pressure parts. Depending on incoming fluid temperatures, sulfuric acid and ammonium hydroxide can also form. All of these contaminants must be considered in the selection of pressure part materials of the OTSGs.

Accelerated corrosion test have been completed by IST to ensure appropriate materials are used for the pressure parts (fin, tube and braze material). An example is accelerated corrosion testing in ASTM G28-97, Method B Solution consisting of 23% H_2SO_4, 1.2% HCl, 1% $FeCl_3$ and 1% $CuCl_2$. Various fin/tube material combinations were used to verify applicability. Figures #10, #11 and #12 indicate results of such testing.

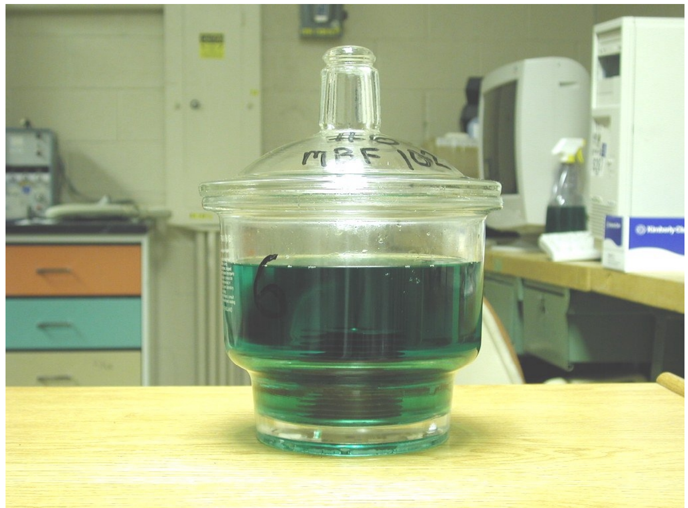

Figure # 10 - ASTM G28-97 Mixture

Figure #11 -
409SS fins / SB423 NO8825 after 48 hours

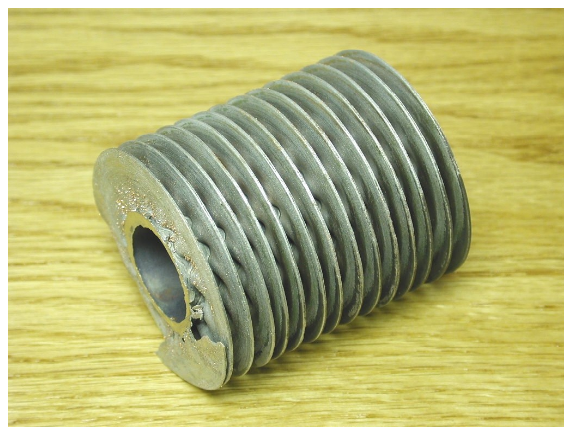

Figure # 12 -
316 SS / SB423 NO8825 after 7 days

The corrosive atmosphere can also lead to plugging of the finned tubes in the water inlet section of the OSTG. This soot leads to degradation in performance and corrosion. Figure #13 is from the feedwater inlet of an OTSG coupled to a LM2500 gas turbine operating on a liquid fuel (diesel oil) and with an SCR system.

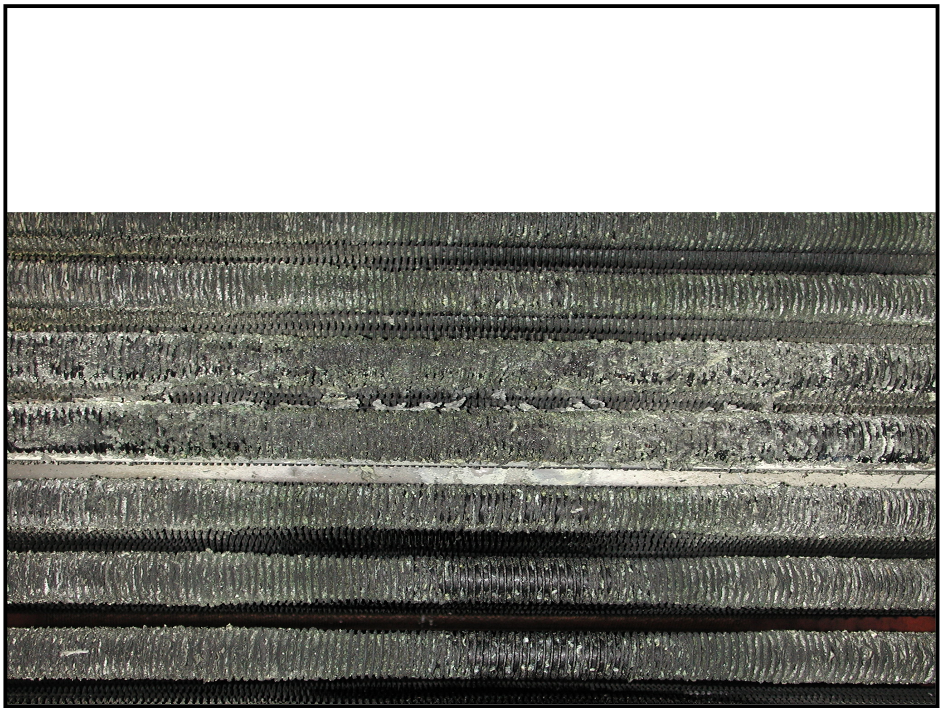

Figure #13 Feedwater Inlet Tubes for an OTSG behind LM2500 gas turbine with SCR

Various methods (water washing, CO_2 blasting) have been used with varying success to remove any deposits that do accumulate over time. While water washing can be used, the waste stream can be considered a hazardous chemical and can also corrode surfaces below the SCR housing.

Another option exists that is limited to the OTSG and its dry running capability. Dry running refers to the OTSG operating without water/steam flowing through the pressure parts. The result is the pressure parts heat up to local gas temperature. The advantages of dry running have been proven in liquid fired gas turbine applications such as diesel oil.

A series of tests were conducted on OTSG's in the early 1980's. Following soot fouling tests in which soot had accumulated on the cold section of the OTSG, cleaning tests were completed. The cleaning tests involved running the OTSG at elevated gas temperatures without feedwater flowing through the OTSG. Dry running tests were run at 840 F for 60 minutes and 900 F for 60 minutes and 100 minutes. Heat transfer performance was fully recovered by performing a dry boiler burnoff at 900 F for 100 minutes. IST currently has a number of OTSG's operating successfully behind liquid fuel fired gas turbines.

Below is a photograph of an exhaust stack from an OTSG during a dry cleaning run. This specific OTSG system is a liquid fuel fired LM2500 gas turbine with an SCR and a feedwater inlet temperature of approximately 70 F. The plume of smoke can be seen escaping from the exhaust stack.

Figure #14 – Exhaust Stack of an OTSG During Soot Cleaning

GAS TURBINE NOISE CONTROL

Gas turbines are powerful energy sources. The exhaust energy generated by the gas turbine flows along the ducting connecting the gas turbine, into the pressure parts of the OTSG and finally out the stack. This exhaust energy, in the form of sound, interacts with the duct walls where some of it is absorbed by the thermal insulation and some of it is transmitted to the environment. Any remaining energy will interact with the tube bundle before leaving the exhaust stack. Analysis of the OTSG is required to ensure the interaction of the energy with the tube bundle will not lead to damage or that the sound leaving the exhaust stack will not exceed site requirements.

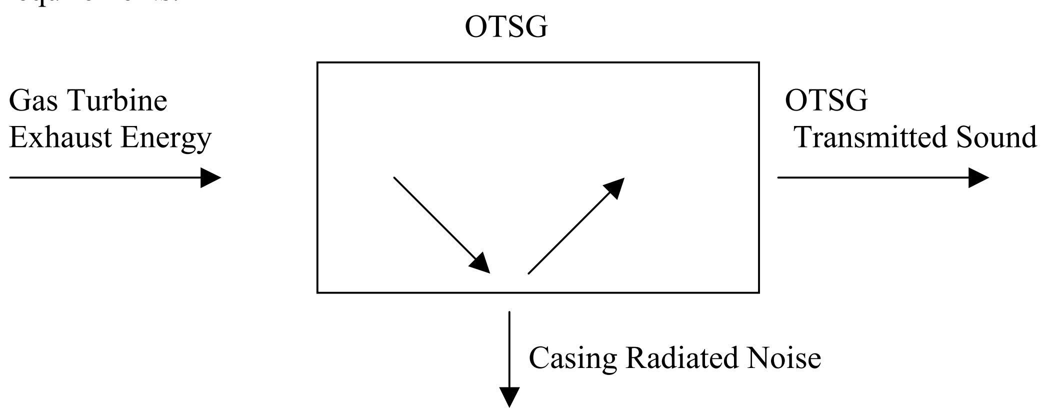

Figure #15 – Gas Turbine Exhaust Energy Path

Acoustic Resonance

An acoustical analysis is required to determine the potential for acoustic resonance. The acoustical analysis identifies the excitation frequencies (forcing frequencies) as a result of the exhaust energy and the potential of exciting the tube bundle (driven component) or ducting.

<u>Excitation (Driving) Frequencies</u>

Significant mechanical and acoustical vibrations can occur if the forcing frequency is matched to the tube bundle acoustic natural frequency. If resonance is present and left unattended, failure can occur from the mechanical fatigue of a component. Furthermore, a state of acoustic resonance will result in noisy operating conditions.

Two distinct mechanisms have been identified as the forcing frequencies present within a tube bundle during operation. The first mechanism is known as 'vortex shedding' and occurs from the periodic shedding of vortices in the wake region, downstream of the tube. The frequency of vortex shedding increases with higher gas flow velocities, and is dependent upon the tube size and arrangement. Vortex shedding has been shown to readily occur within the tube bank from 3 to 12 rows deep. However, there have been cases where vortex shedding has been identified to occur beyond 12 rows. Therefore, the potential for vortex shedding must be assumed throughout the entire tube bundle.

The second mechanism is referred to as 'turbulent buffeting ', and appears in a tube bank 5 to 9 rows deep and becomes fully established by rows 10 to 12. The turbulent buffeting frequency spectrum consists of a central dominant frequency surrounded by a wide range of frequencies. Like vortex shedding, turbulent buffeting increases with higher gas flow velocities and is dependent upon the tube bank configuration. Note that vortex shedding and turbulent buffeting can occur at the same time within a tube bundle. The noise generated from turbulent buffeting has been found to be much louder than the noise generated by vortex shedding.

Tube Bundle /Ducting Resonance

Resonance can occur in the gas path both in the transverse and longitudinal directions and in the heat transfer tubes. When acoustic waves of equal amplitude are travelling in opposite directions, they add in such a way as to produce a wave that oscillates in amplitude but does not move in space. Such a wave field is called a standing wave or a mode. Standing waves are produced in ducting when there are strong reflections at walls or terminations and can result in noise levels as high as 130 dB.

The first mode of acoustic vibration is the easiest to excite, followed by the 2^{nd}, 3^{rd} ... etc. Realistically, only the first two modes of vibration can be expected to be excited by the vortex shedding and turbulent buffeting excitation forces although IST experience has indicated that the 4^{th} and 5^{th} modes must also be evaluated in certain cases.

Resonance in the gas path is caused through the excitation of a fluid column in either the transverse or longitudinal direction. The excitation of the gas is similar to the operation of an organ pipe. To prevent gas path resonance, acoustic baffles are installed parallel to the tubes, and extend the full tube bundle length. Transverse baffles, on the other hand, are installed perpendicular to the tubes, and cover the entire width of the tube bundle. The height of the baffles are dependent upon the acoustic analysis, and can range from a small number of tubes to the complete tube bundle height.
The following figures will illustrate the interaction of the excitation frequencies and the potential for either gas path resonance.

Figure #16 indicates an analysis of an OTSG without any acoustic baffles. There is a potential for duct resonance between tube row one to eleven as the excitation frequencies (mainly turbulent buffeting) approach the first mode of acoustic resonance of the gas channel in the transverse direction.

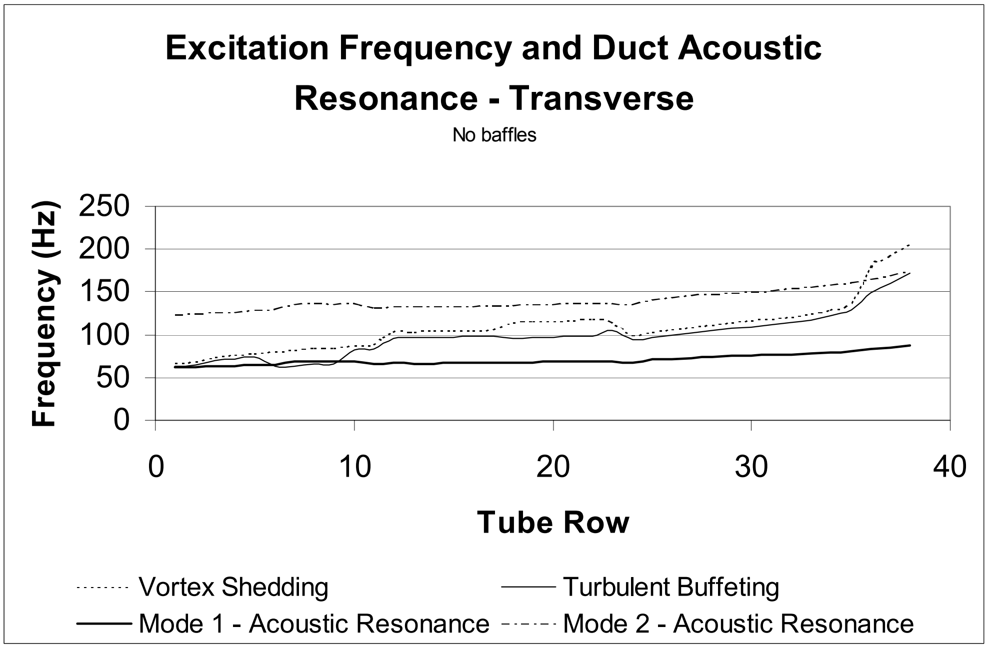

Figure #16 Duct Acoustic Resonance without Acoustic Baffles

The addition of acoustic baffles will change the duct acoustic resonance. Figure #17 indicates an analysis of an OTSG with two rows of acoustic baffles. The excitation frequencies are now safely below the duct acoustic resonance frequencies.

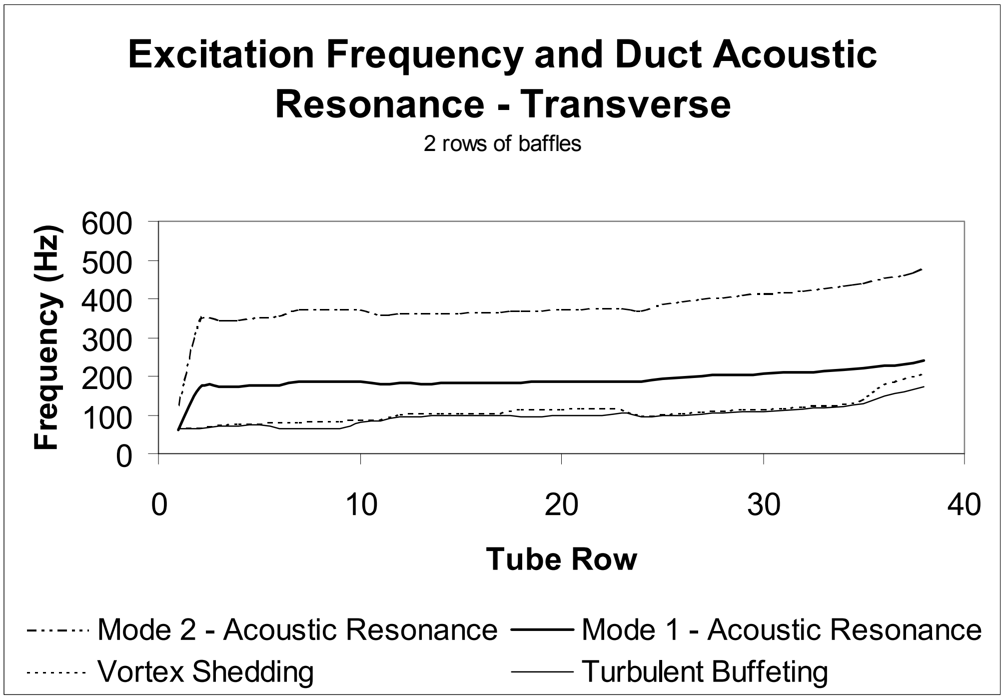

Figure #17 – Duct Acoustic Resonance with Acoustic Baffles

Tube resonance can also occur if the excitation frequencies approach the natural frequency of the tubing. As indicated in Figures #18 and #19, this becomes a concern at low gas turbine operating loads as the driving frequencies decrease. At maximum gas turbine loads (Figure #18), gas velocities are maximized resulting in high excitation frequencies which are safely away from the tube resonance frequencies. As the gas turbine load decreases, the driving frequency approaches the tube resonance frequency.

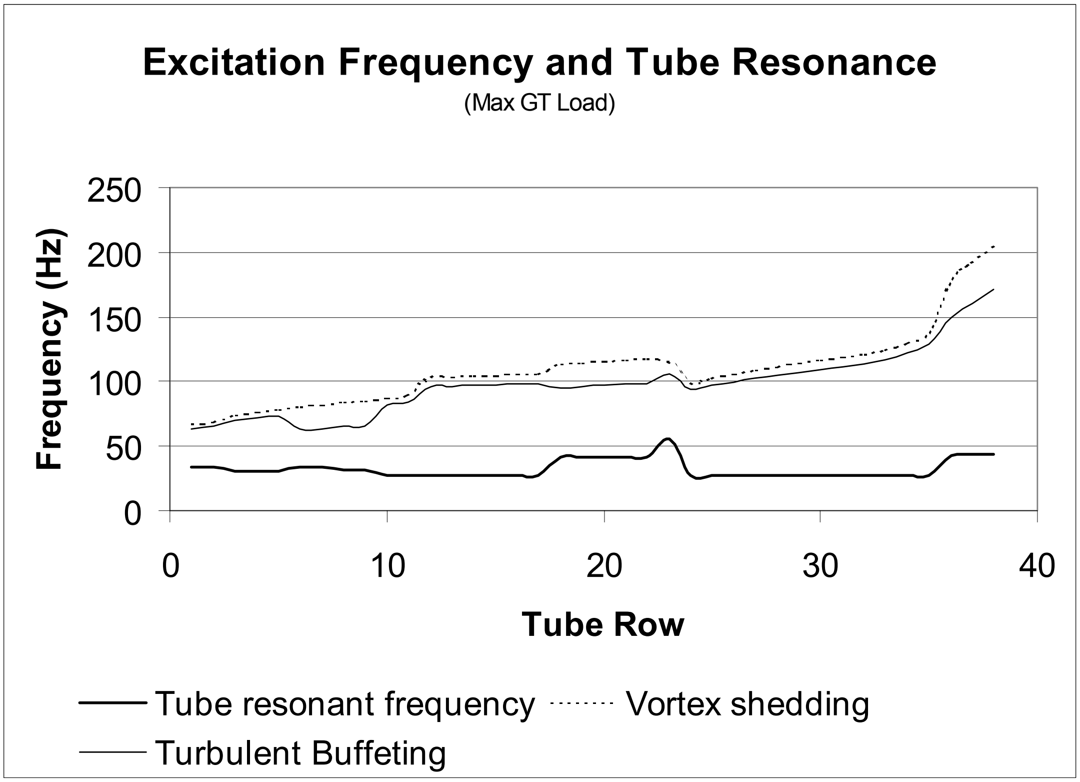

Figure #18 – Potential for Tube Resonance at Maximum GT Load

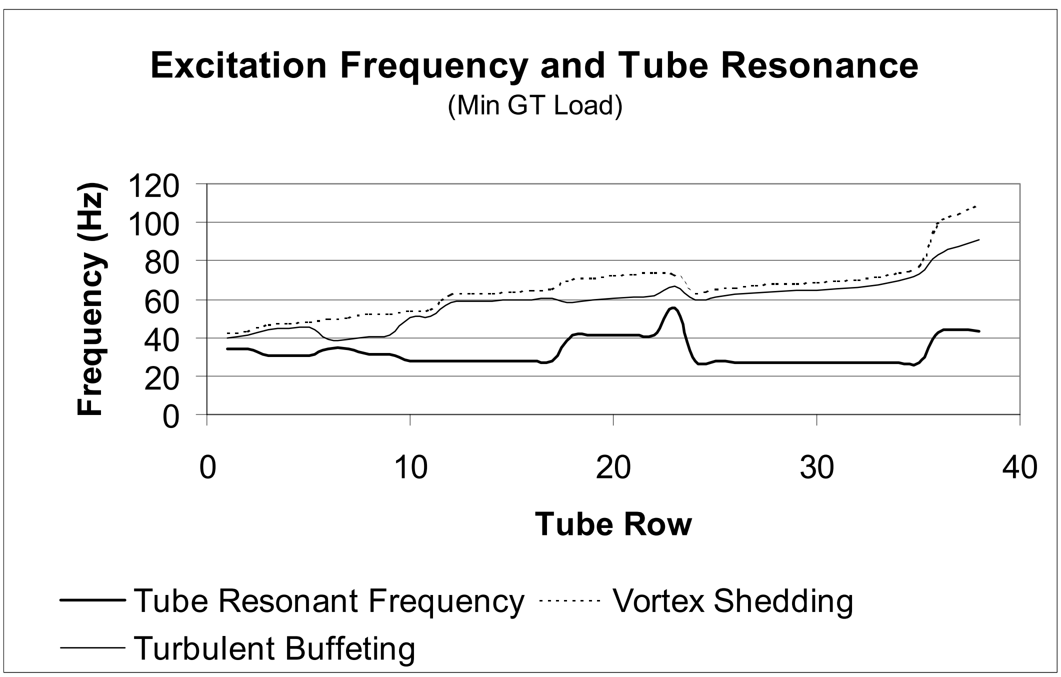

Figure #19 – Potential for Tube Resonance at Minimum GT Load

As shown in Figure #19, a potential for tube resonance exists at rows five to seven as the turbulent buffeting frequency approaches the tube resonant frequency. The only possible solution is to modify the tube resonance frequency by either modifying tube diameter, thickness or fin characteristics.

Transmitted Energy

Sound can escape from the OTSG either through the duct walls (transmission loss) or through the exhaust stack (insertion loss). In the case where the sound escaping the exhaust stack exceeds allowable limits, additional absorption is provided by a splitter silencer inserted into the ducting downstream of the gas turbine. Figure #20 shows a typical set of splitter silencers in the inlet duct of an OTSG.

Figure #20 – Inlet Duct Silencer Splitters

IST has completed significant field testing to accurately determine the insertion loss provided by the tube bundle to allow accurate sizing of splitter silencers or duct silencers. Typical sound power levels from gas turbines and OTSG insertion losses are listed in Table #1.

Gas Turbine	Octave Band Center Frequency								
	31.5 Hz	63 Hz	125 Hz	250 Hz	500 Hz	1000 Hz	2000 Hz	4000 Hz	8000 Hz
LM6000 PWL (dB)	137	138	137	140	137	126	122	120	109
RB211 PWL (dB)	144	145	144	141	142	145	129	132	132
501G PWL (dB)	149	150	150	141	142	143	145	154	144
Typical OTSG Insertion Loss (dB)	17 to 31	18 t 31	21 to 29	21 to 39	22 to 40	25 to 44	33 to 56	40 to 58	39 to 60

Table #1 – Typical GT Sound Power Levels and OTSG Insertion Losses

An example of the sound absorption provided by the OTSG without silencer splitters is provided in Figures #21 and #22. Typical sound levels are provided for an LM6000 gas turbine and OTSG.

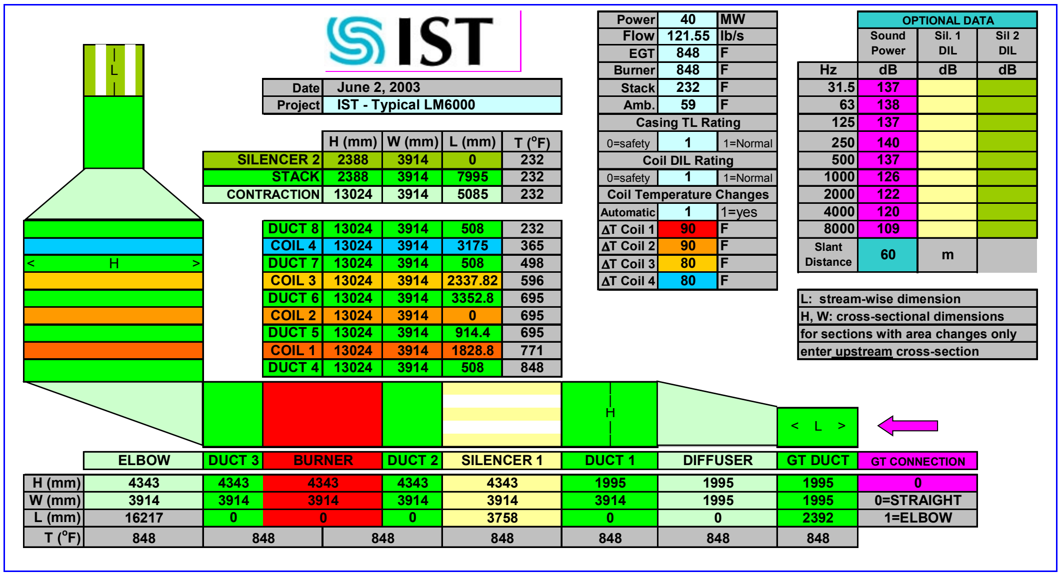

Figure #21 Typical LM6000 GT Sound Power Levels

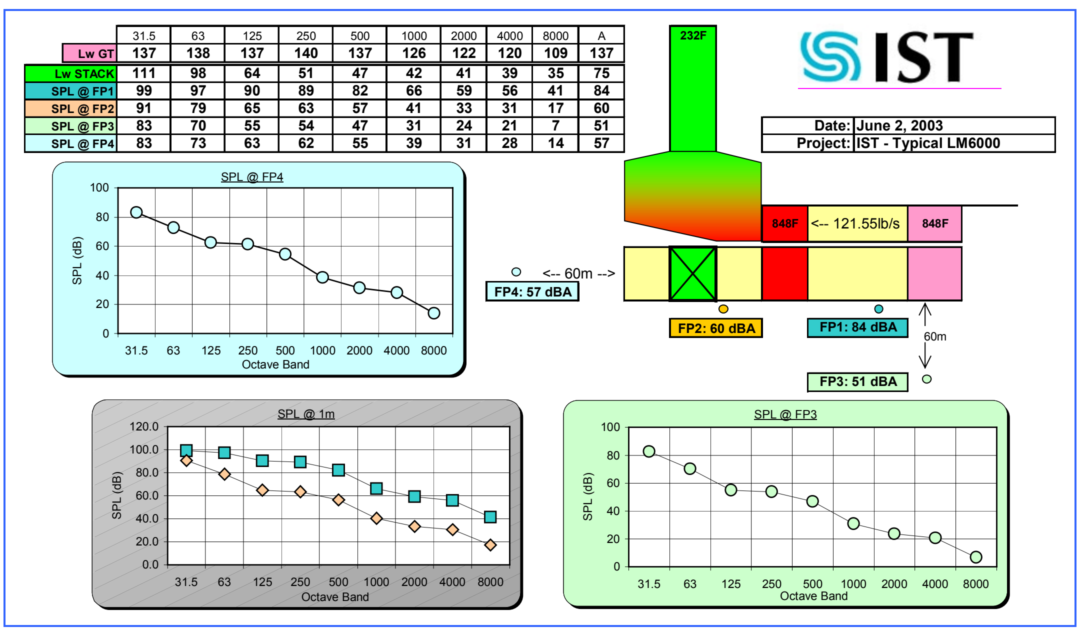

Figure #22 Typical Exit Sound Levels at the Exit of the OTSG

As seen from Figure #22, noise levels of approximately 60 dBA and 85 dBA (locations FP1 and FP2) are typical local to the OTSG without silencer splitters.

If the breakout noise from the ducting is too high, an acoustic shroud can be placed around the inlet duct. Figure #23 shows an acoustic shroud around the inlet duct of an OTSG.

Figure #23 - Acoustic Shroud placed outside of duct walls

Combustor Noise

With the development of DLE or Low NOx gas turbine combustors there have been instances where combustion instability has led to a combustor resonance. Combustor resonance results in high amplitude, low frequency noise which leads to pressure fluctuations in both the combustor as well as downstream equipment such as the OTSG structure or ducting. If the combustor resonance coincides with the natural frequency of the structure or ducting panels (typically between 20 to 30 Hz), significant structural / panel oscillations can occur.

GAS TURBINE EXHUAST FLOW PROFILE CORRECTION

The gas flow distribution leaving the gas turbine is typically non-uniform. Figure #24 shows a typical gas flow distribution at the outlet of an LM6000 diffuser.

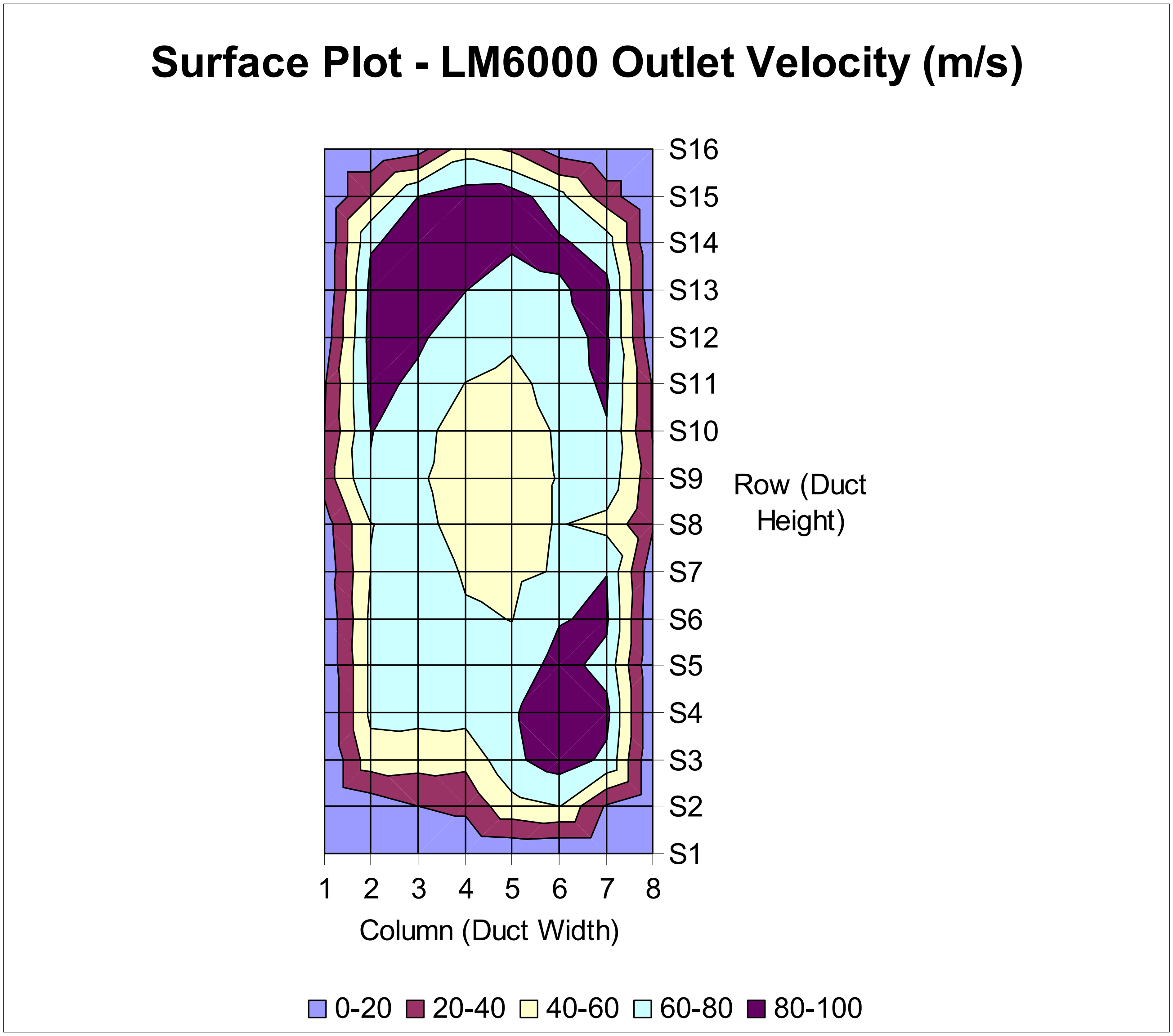

Figure #24 – LM6000 Outlet Velocity Distribution

For proper performance this gas velocity distribution must be corrected. A uniform gas velocity profile at various locations in the OTSG is critical to meeting guaranteed performances. These locations are upstream of the duct burner, upstream of the tube bundle, upstream of SCR or CO catalyst and at the stack measurement locations. For these reasons, accurate prediction of gas velocity profile and correction of the gas velocity profile is critical. Until recently the engineering tool of choice for analysis of the flow distribution has been scale modeling.

Physical modeling has been used for a number of years. The models are typically 1/8th scale and constructed from clear acrylic to allow visualization. To measure the flow characteristics, ambient air is passed through the scale model at the specified flow rate. Velocities are measured with a pitot tube or a hot wire anemometer. Static pressures are measured using water or electronic manometers. Flow visualizations can also be made by passing smoke through the model. A typical model is shown in Figure # 25.

Figure #25 – Typical Flow Model

CFD (computational fluid dynamics) is beginning to be used successfully for the same application. CFD is a numerical tool to analyze flows. The software solves the relevant conservation equations (mass, momentum and energy) to which suitable boundary conditions (constraints) are applied to. The level of detail that can be modeled is a function of the number of elements that can be readily accommodated by the computer. A typical model is shown in Figure #26.

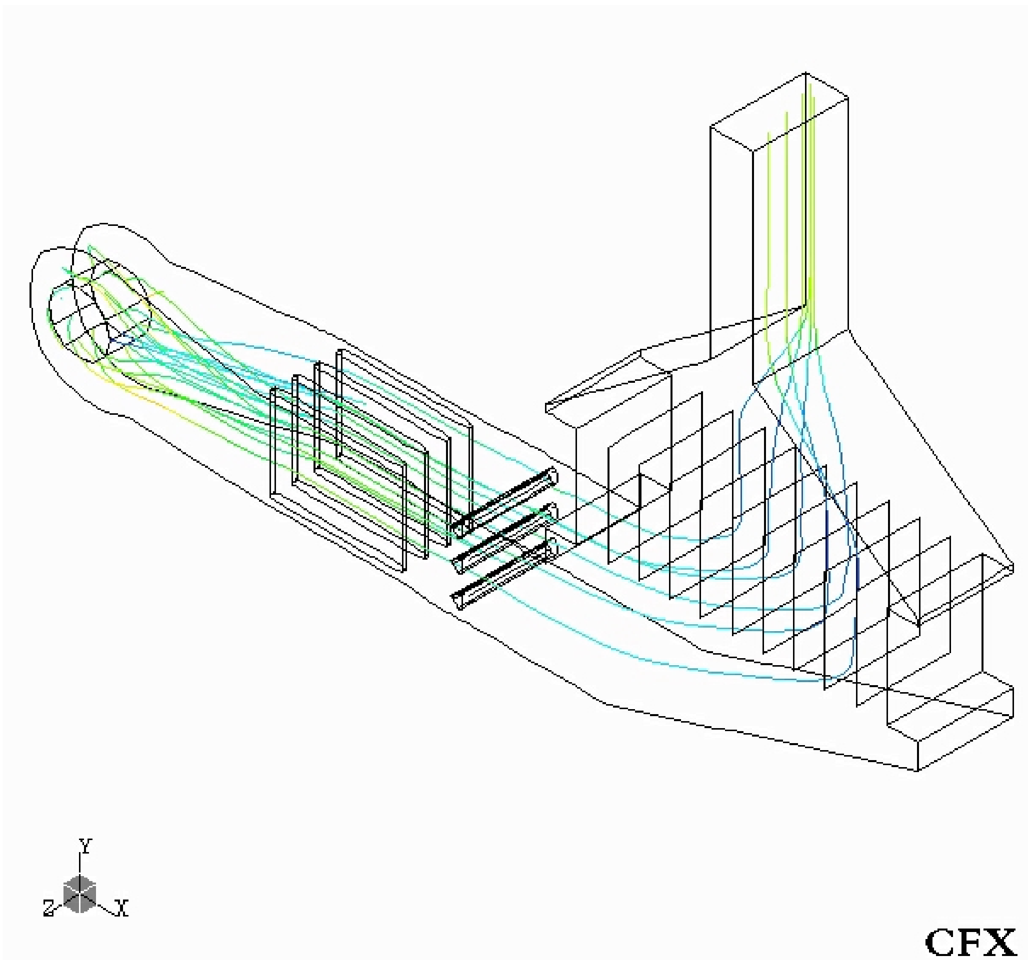

Figure #26 – Typical Duct Fired CFD OTSG Model

Advantages exist in predicting gas temperatures as well as flow distribution in CFD. A typical model including temperature distribution is shown in Figure #27.

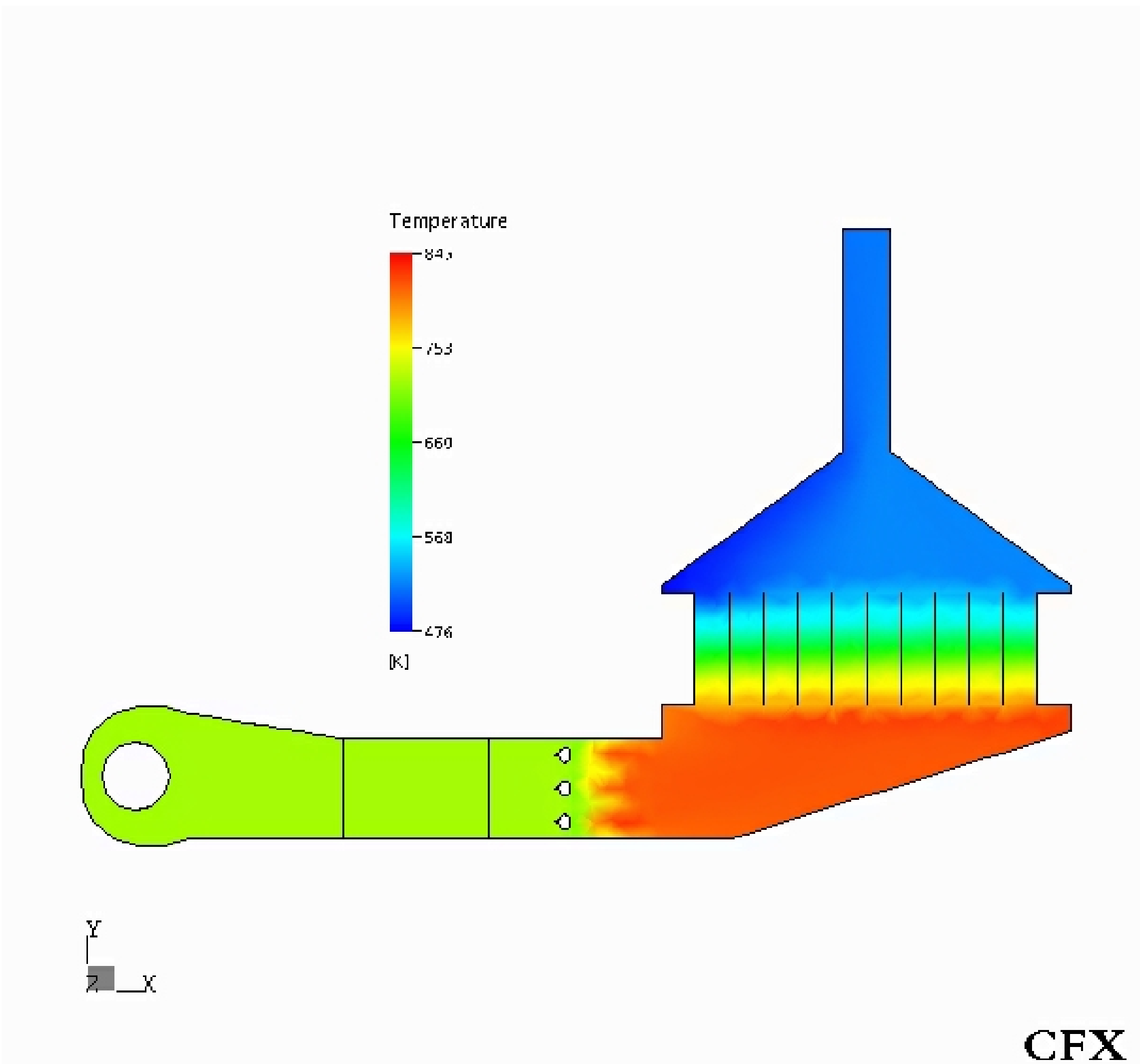

Figure #27 – CFD Model of Temperature Distribution

To correct flow maldistribution, turning vanes and variable porosity plates are commonly used. Figure #28 shows a variable porosity plate upstream of a duct burner.

Figure #28 – Variable Porosity Plate

Typical gas side pressure drop for a variable porosity plate ranges from 0.5 inches water column to 3 inches water column.

GAS TURBINE POWER AUGMENTATION

Gas turbine steam injection is being used today for blade cooling, NO_x reduction or, most commonly, for power augmentation. The steam injection process most commonly consists of injecting steam or water into the head end of the combustor (for NO_x reduction) and into the compressor discharge, increasing mass flow and power output. Gas turbines generally are designed to allow steam flows up to 5% of the compressor airflow with flows as high as 10% allowed on some gas turbines. A steam injection flow of 5% of total flow can increase power output by approximately 17.5% for all ambient conditions (independent of temperature, humidity etc.) and also reduce NO_x levels.

The main advantages of the steam injection process are:

a) The power increase can be realized independent of ambient conditions (temperature or humidity). The power augmentation process will increase power in all climates and at all times of the year.
b) Power augmentation results in greatly increased NO_x reductions (see Figure #29). The injected steam reduces the flame temperature thereby reducing NO_x emissions.

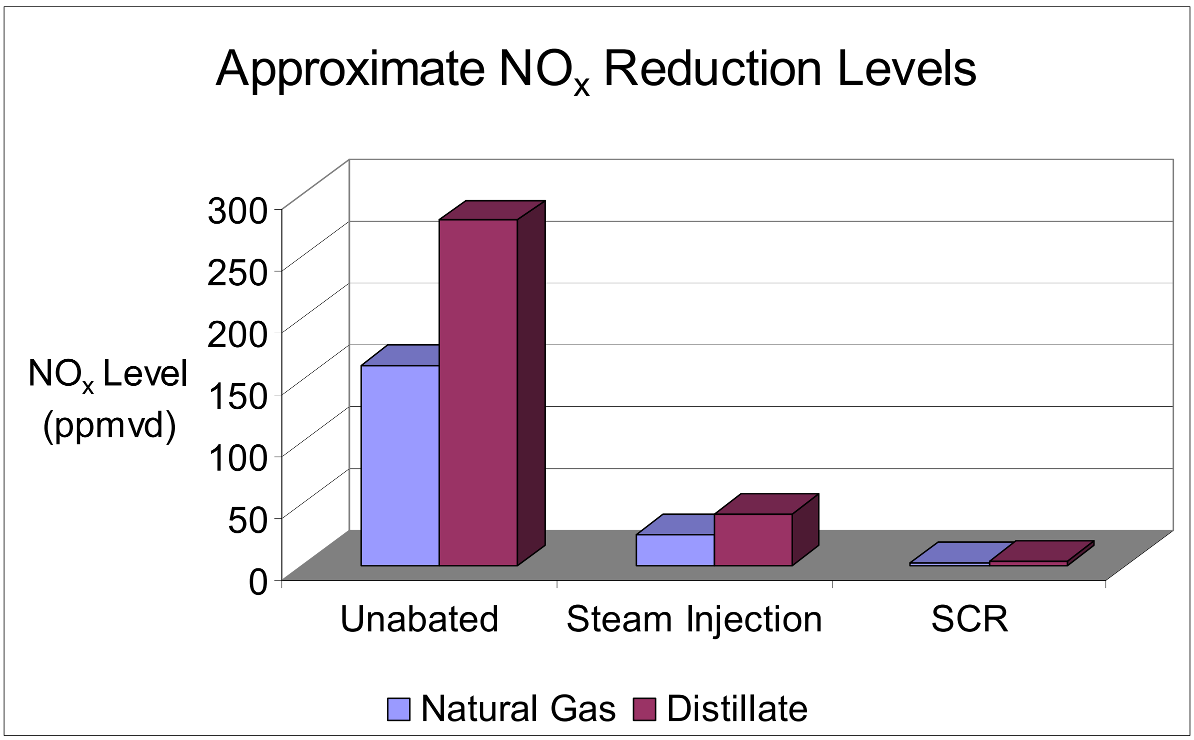

Figure #29 – Typical NO_x Reductions

A process diagram of the steam injection process in shown in Figure #30.

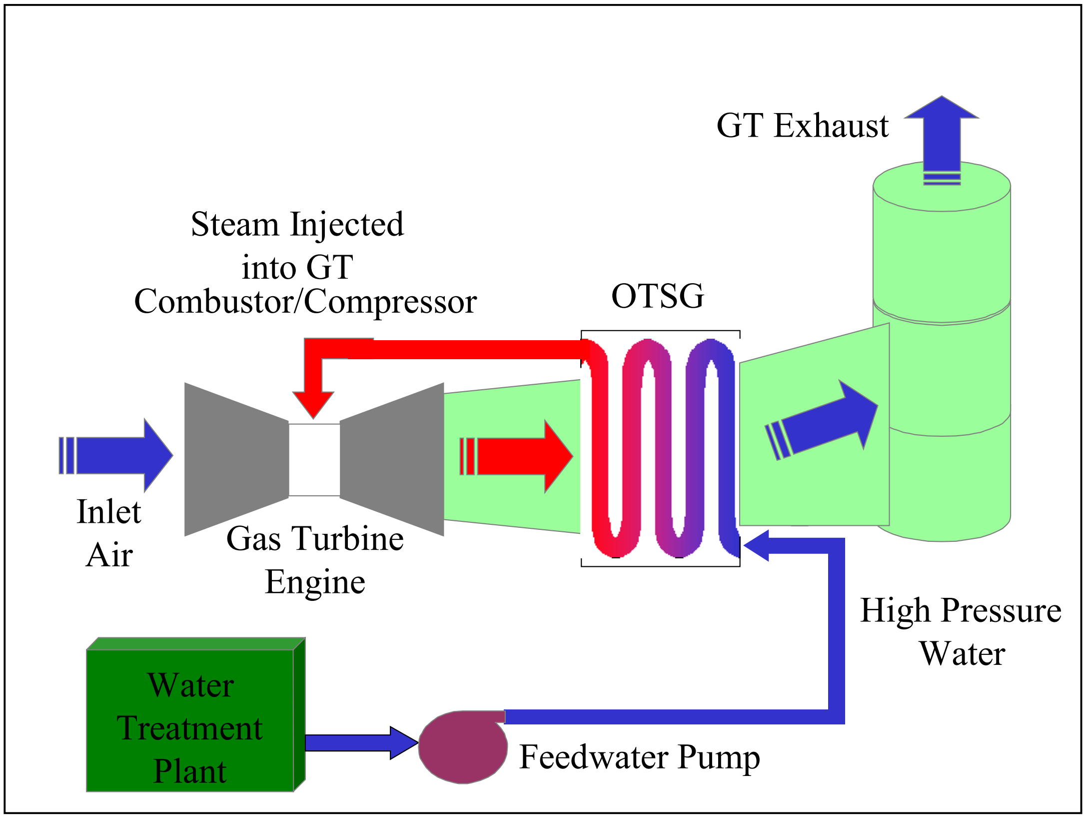

Figure #30 – Steam Injection Process

The steam injection process contains two major components – the gas turbine and a single pressure level OTSG. Superheated steam is produced in the OTSG and injected into the compressor and/or into the head end of the combustor. Steam is injected upstream of the combustor for NO_x reduction and into the compressor discharge for power augmentation. Both of these applications require clean, dry steam at approximately 300 psig and with approximately 50 F of superheat. Typical steam purity requirements for gas turbine injection are cation conductivity limits less than 0.25 µS/cm (total solids less than 50 ppb) with some gas turbines requiring cation conductivities as low as 0.11 µS/cm. These steam purities meet or exceed the requirements for the OTSG.

Auxiliaries such as feedwater treatment, instrumentation, controls and piping are also required to complete the system. The ducting and exhaust stack may or may not be required as these items are required for a simple cycle installation. Addition of the OTSG to the ducting system will result in approximately a 4 inches WG addition in pressure loss and a subsequent reduction in gas turbine efficiency (approximately 0.4%).

Steam Injection Process Control System

For the single pressure steam injection OTSG there is a single controlled analog output to the feedwater flow control valve that modulates feedwater flow rate to obtain the desired superheated steam flow required by the gas turbine. If the OTSG can produce more steam than is required for the given gas turbine load, the steam outlet temperature can be controlled with an attemperator. For most applications, the gas turbine combustion controls will calculate the required steam flow and provide a mass flow demand signal to the feedwater controller. The sum of feedwater into the OTSG and feedwater into the attemperator shall be controlled to meet this demand. Attemperation is managed by diverting a portion of the feedwater to the steam outlet line. A typical flowsheet is shown in Figure # 31.

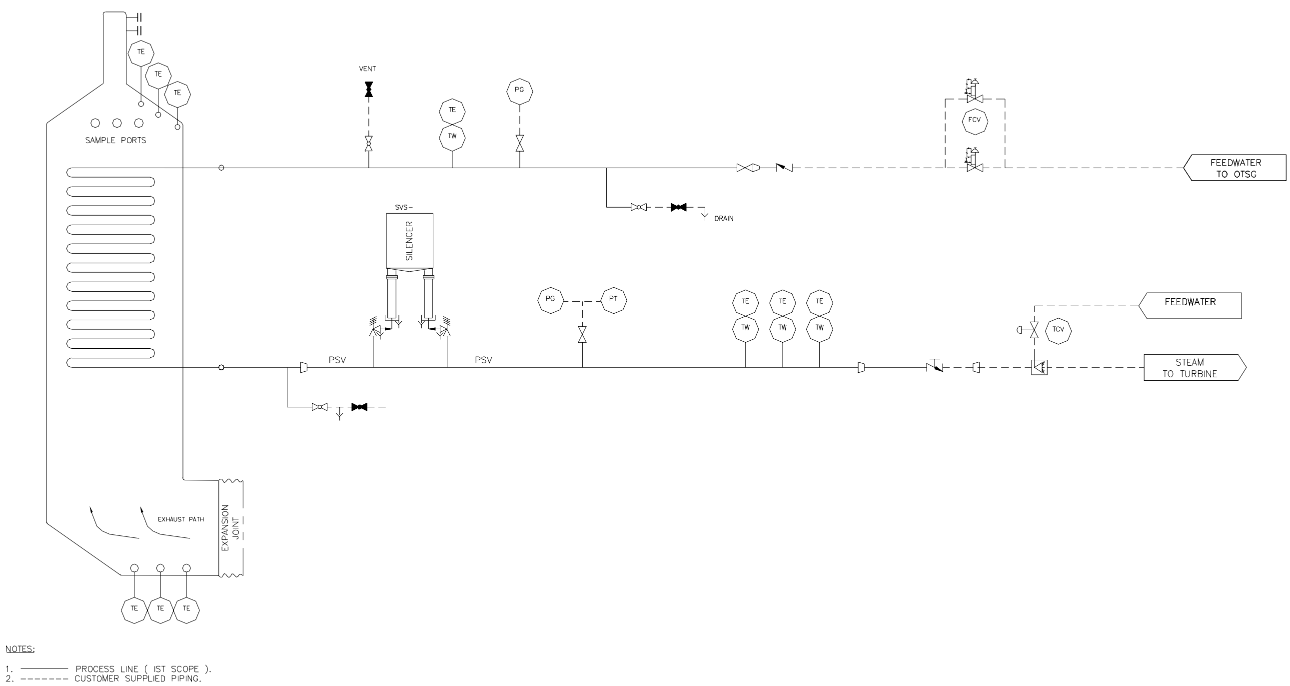

Figure # 31 – Typical Steam Injection Process Flowsheet

The goal of the control system is to generate the required steam flow and temperature from the gas turbine exhaust heat, while providing both rapid responses to gas turbine load transients and accurate control of steam temperature. Measured parameters include steam temperature, steam pressure, turbine exhaust gas temperature, feedwater temperature, stack temperature and feedwater flow rate. Calculated values include feedwater and steam enthalpy. The gas turbine manufacturer provides the gas mass flow calculation.

Preventing damage to any system component, in the event of a control failure is the system design criteria. In some instances this requires redundant instrumentation or control. In other cases triplication of critical measurements are made, and two of three voting logic is used. Triplication is used when it is very costly to shutdown the power plant to replace a failed instrument.

Critical OTSG parameters should be monitored by the controller and an alarm sounded whenever an operating limit is approached. In some cases this allows the operator to take some corrective action prior to the system being shutdown.

The footprint impact can be eliminated on a steam injected application with a vertical tube OTSG as the OTSG is inserted into the existing duct. A typical installation is shown in Figure # 32.

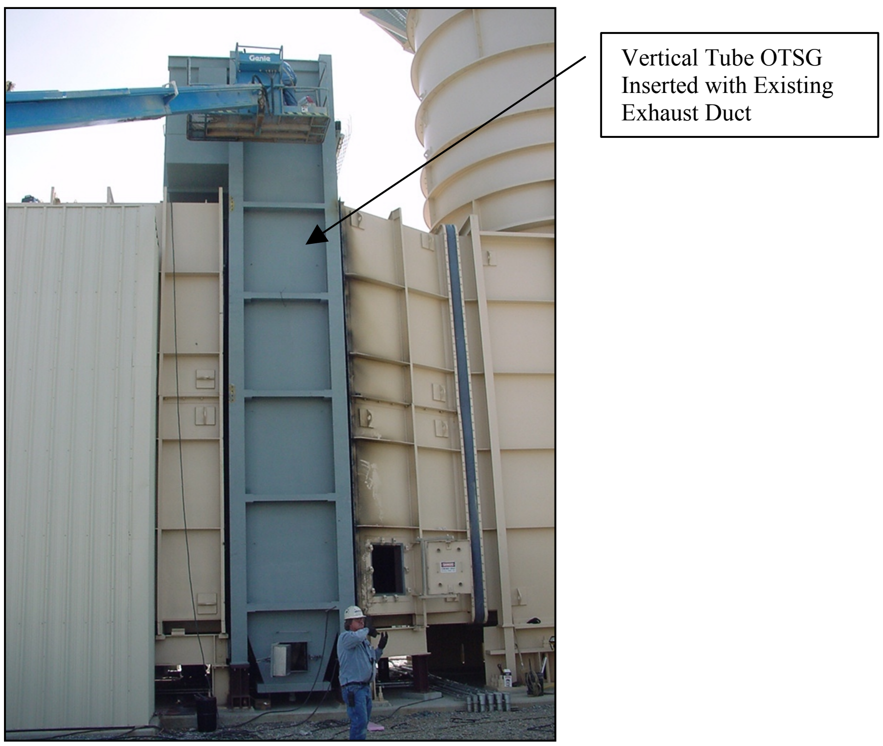

Figure # 32 Steam Injected OTSG
Frame 7FA Application

SUMMARY

This paper has presented four critical areas in which the OTSG design can be affected through the selection and operation of the gas turbine.

Gas turbine emissions (NO_x and CO) requires modification to the OSTG design and increases complexity. Emission reduction catalysts and ammonia injection hardware must be inserted at the proper location in the tube bundle and pressure part materials must be selected to provide reliable operation in corrosive environments.

The noise emissions from gas turbines must be analyzed to ensure tube bundle or duct resonance will not occur. Resonance may lead to premature failure of OTSG components. In addition, an analysis is required to determine if silencer splitters or acoustic shrouds are required to maintain noise levels as per site requirements.

The gas turbine exhaust flow profile can be non-uniform. This can lead to under performance of the OTSG or to damage of ducting components. The exhaust flow profile must be properly modeled and corrected to ensure adequate flow distribution.

Finally, gas turbine steam injection applications such as power augmentation, NO_x reduction or blade cooling can lead to special design requirements of the OTSG such as feedwater quality, footprint requirements and controls.