Innovative Steam Technologies

GAS TURBINE PERFORMANCE ENHANCEMENT WITH ONCE THROUGH HEAT RECOVERY STEAM GENERATORS

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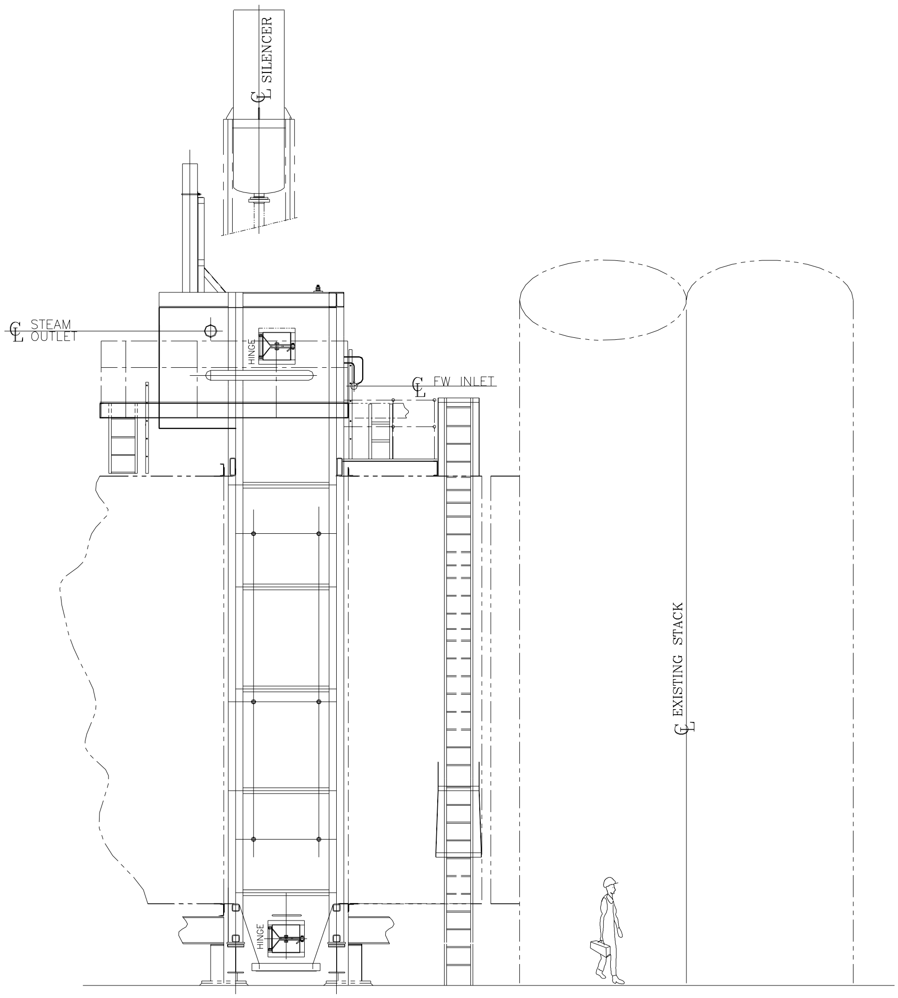

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GAS TURBINE PERFORMANCE ENHANCEMENT WITH ONCE THROUGH HEAT RECOVERY STEAM GENERATORS

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ABSTRACT

Plant owners and operators are examining the available options at increasing existing simple cycle gas turbine power plant output to meet peak power requirements. Various methods are available for improving the performance of gas turbines during retrofit applications. The gas turbine enhancements can be classified into two major categories: inlet cooling and power augmentation.

Inlet cooling options cool the inlet air to the combustion turbine making the incoming air denser. The dense air increases mass flow and subsequently increases the power output of the gas turbine. All inlet cooling methods are dependant on ambient conditions (ambient temperature and humidity). Operating cooling systems at ambient temperatures below 59 F (15 C) leaves the potential for icing the compressor. In humid climates when saturation is reached (100 % relative humidity), inlet coolers are unable to evaporate more water into the air stream.

Steam has been injected into gas turbines for many years for power augmentation. The process consists of injecting steam into the head end of the combustor (for NO_x reduction) and into the compressor discharge, increasing mass flow and power output. The injected steam must contain at least 50 F (28 C) superheat and be at pressures comparable to fuel gas pressures. Steam injection of gas turbines for power augmentation has the advantage of not being limited to ambient conditions and can be operated year round in humid or arid climates.

Most often the steam source is from an existing steam generator coupled to the gas turbine. Steam is taken from the appropriate section of the heat recovery steam generator (HRSG) and admitted into the gas turbine. Innovative Steam Technologies (IST) has successfully been involved in retrofit applications where once through heat recovery steam generators (OTSGô) have been retrofit into existing simple cycle applications to achieve increased power.

Special design considerations are required for OTSGô steam injection applications including steam purity, material selection to prevent erosion and corrosion, rapid start capabilities, cyclic operation, dry operation during off-peak periods and unattended operation (or reduced operators).

This paper will address the special design considerations required when successfully retrofitting a steam generator into a simple cycle gas turbine plant for power augmentation.

NOMENCLATURE

OTSGô ñ Once Through heat recovery Steam Generator
PPA ñ Power Purchase Agreement
STIG ñ Steam Injected Gas Turbine
BOP ñ Balance of Plant
ROI ñ Return on Investment
kW ñ Kilowatt (Energy)
Btu ñ British Thermal Unit
PMT ñ Payment
Capex ñ Capital Expenditure
Opex ñ Operating Expenditure
DCSR - Debit Coverage Service Ratio

INTRODUCTION

Various methods are available for improving the performance of gas turbines during initial plant design or with retrofit applications. The gas turbine enhancements can be classified into two major categories: inlet cooling and power augmentation.

a) Inlet Cooling

Gas turbines that run at constant speed are constant volume machines with the air used for combustion being drawn into the gas turbine. The specific volume of this air is directly proportional to the incoming air temperature. Cooling this inlet air results in a more dense combustion air. As the air is denser, it gives the gas turbine a higher mass flow rate and pressure ratio, resulting in an increase in power output. Inlet cooling works on the principle of reducing the temperature of the inlet air stream through water evaporation. The result is cooler, more humid air.

There are many inlet cooling options with the most common being evaporative cooling, inlet fogging and inlet chilling. While inlet cooling options such as inlet fogging can be applied to all gas turbines, they are very sensitive to humidity and inlet temperature and are most useful for hot summer peaking applications in areas with low humidity (the less moisture in the inlet air entering the gas turbine inlet, the more effective are fogging and evaporative cooling). These methods also result in very small reductions in NO_x. A typical pressurized water fog system consists of a series of high-pressure pumps ranging from 1000 psi to 3000 psi, a control system and an array of tubes containing the fog nozzles.

b) Power Augmentation

This process 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 up to 5% of the compressor airflow with flows as high as 10% allowed on some gas turbines. The injected steam must contain at least 50 F (28 C) superheat and be at pressures comparable to fuel gas pressures. A steam injection flow of 5% of total flow will 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. The injected steam reduces the flame temperature thereby reducing NO_x emissions.

STEAM INJECTION PROCESS

A process diagram of the steam injection process in shown in Figure #1.

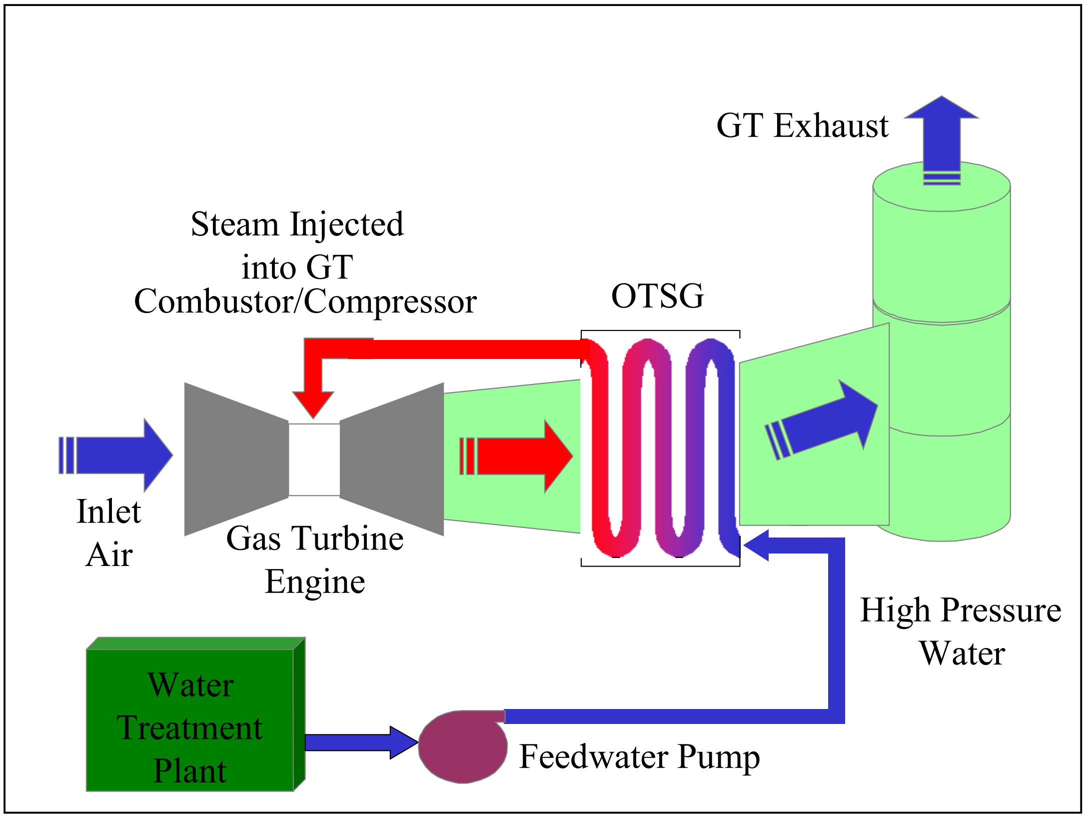

Figure #1 ñ Steam Injection Process

The steam injection process contains two major components ñ the gas turbine and a single pressure level OTSGô . Superheated steam is produced in the OTSGô 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. 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 OTSGô 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 OTSGô 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 # 2.

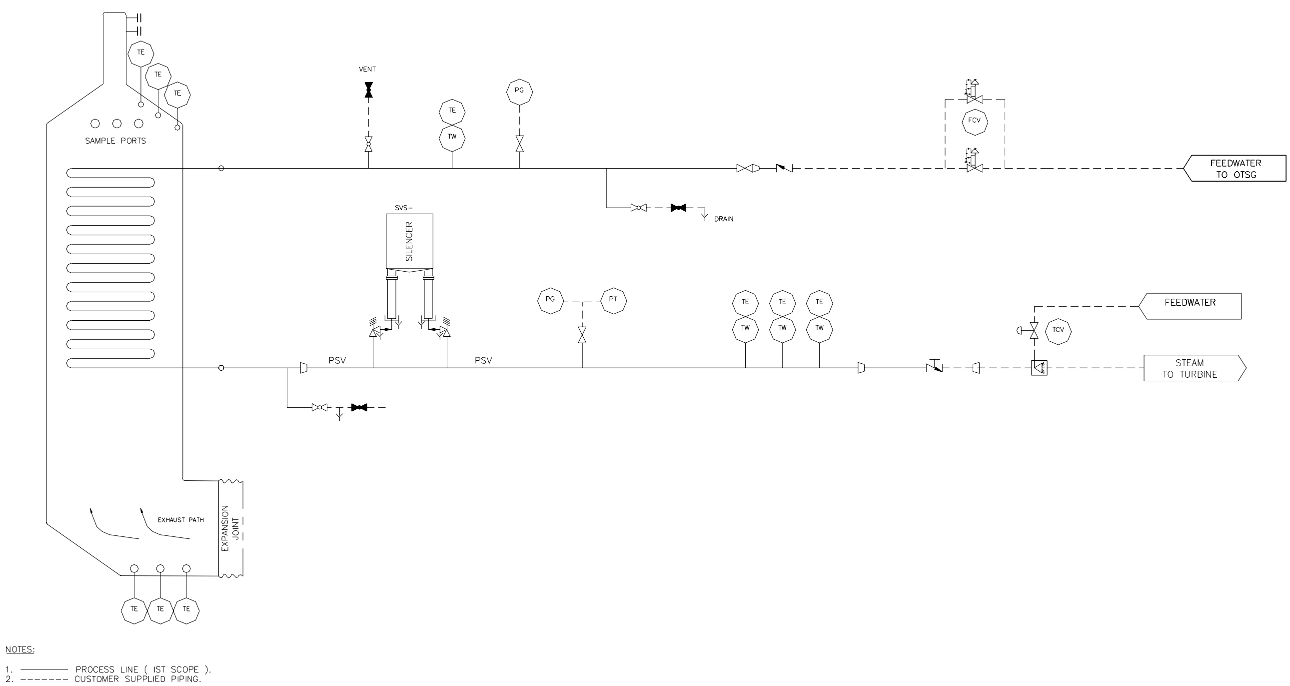

Figure # 2 ñ Typical Steam Injection Process Flowsheet

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.

CHARACTERISTICS AND ADVANTAGES 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 #3.

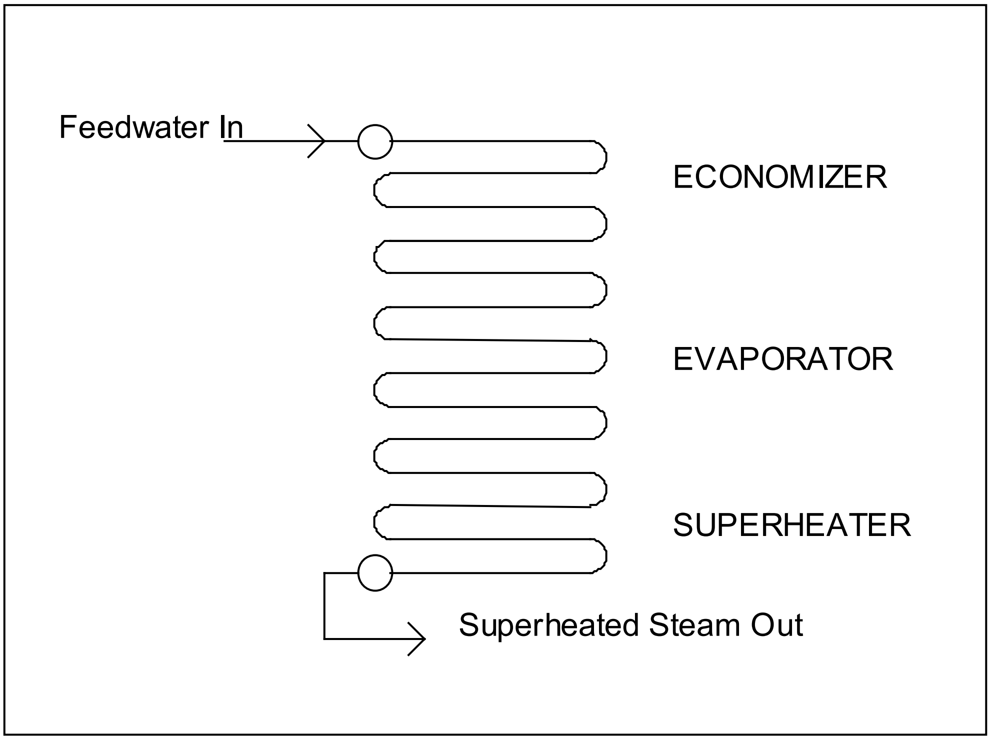

Figure #3 ñ Once through steam generator (OTSGô)

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.

OTSGís can be supplied in both horizontal tube/vertical gas flow arrangements (Figure #3 and #4) as well as vertical tube/horizontal gas flow arrangements (Figure #5 and #6) to match customer requirements.

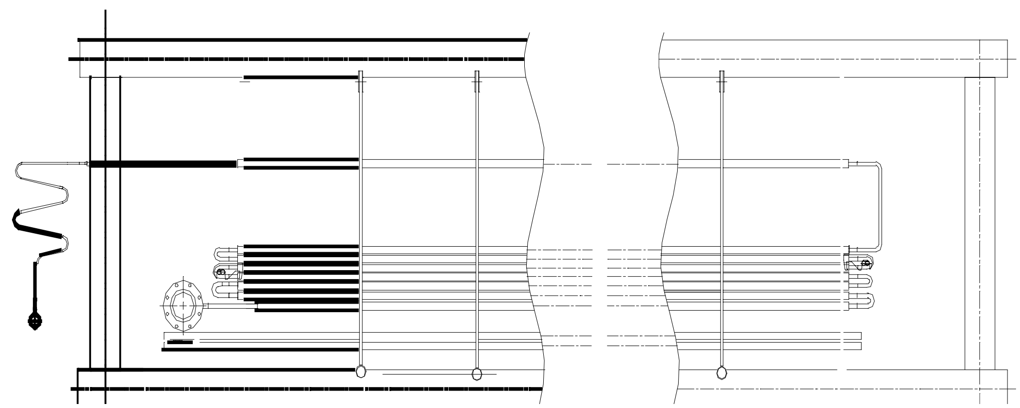

Figure #3 ñ Horizontal Tube/Vertical Gas Flow Arrangement

Figure #4 ñ Horizontal Tube/Vertical Gas Flow Arrangement
LM6000PC Gas Turbine

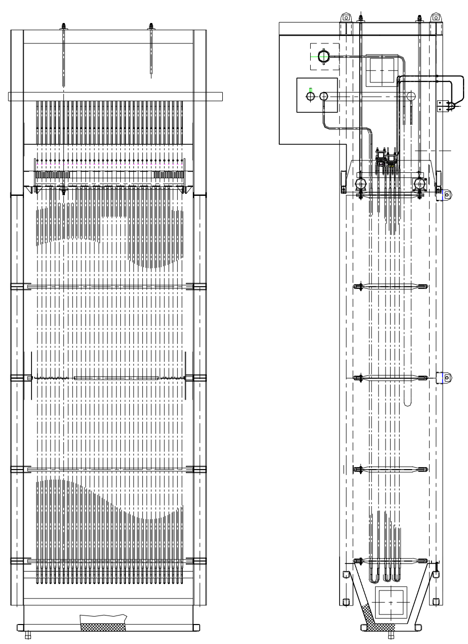

Figure #5 ñ Vertical Tube/Horizontal Gas Flow Arrangement

Figure #6 ñ Vertical Tube/Horizontal Gas Flow Arrangement
Frame 7FA Gas Turbine

APPLICATION THE OF OTSG TO STEAM INJECTION PROCESS

OTSG'sô have been successfully applied to the steam injection process for both NO_x reduction and power augmentation and is uniquely matched to the demanding operational requirements of gas turbine steam injection applications. The significant design features of the OTSGô are as follows.

a) Injection Steam Requirements

Steam injection quality is crucial to gas turbines. Demineralized water is required for all gas turbine water/steam injection processes (inlet fogging, water/steam injection etc.). Any solids carryover can result in premature erosion, corrosion and fatigue of gas turbine components. 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 OTSGô .

Unlike drum type boilers, the OTSGô has no drums and is not subject to the shrink and swell of drum level. The water to steam transition occurs in the tubing and any solids removal is completed prior to entry into the steam generator. This allows for continuous water quality through startups, shutdowns and transients without the possibility for carryover. OTSG'sô can also be fabricated completely from high nickel tubing and alloy external piping, eliminating the risk of iron carryover and flow assisted erosion/corrosion associated with carbon steel or low alloy tubing and external piping. The high nickel tubing also allows for increased oxygen levels that may make the need for mechanical dearation unnecessary. In some instances feedwater can be directly admitted into the cycle without any oxygen treatment. OTSGsô can be designed for low feedwater applications as dictated by plant design. In some applications water is admitted to the OTSGô at water temperatures as low as 59 F (15 C).

b) Operational Requirements

Peaking and Cyclic Service

Steam injection is most often applied to plants requiring peaking and cyclic service. These applications require fast start capabilities and response to quick load changes. In peaking duty, most of the time the OTSGô is in cold standby waiting to be dispatched. This type of operation can be very challenging for traditional drum type HRSGís. Traditional drum type HRSGís are limited in their fast response and transient capability by the steam drums and associated water inventory and mass of metal which require heating. Using an OTSGô and eliminating the drums and interconnecting piping, the fast start capabilities are vastly improved.

Part Load Operation

Unlike traditional natural circulation or forced circulation HRSGís, the OTSGô does not have a steam drum. Water enters at one end of the OTSGô through the inlet header and exits the other end of the OTSGô as superheated steam through the outlet header. The evaporator section is free to move throughout the bundle depending on the operational load. In traditional natural circulation (Figure #7) or forced circulation HRSGís, the steam drum forms a distinct boundary between the economizer, evaporator and superheater. This limits the flexibility of load following for the steam generator.

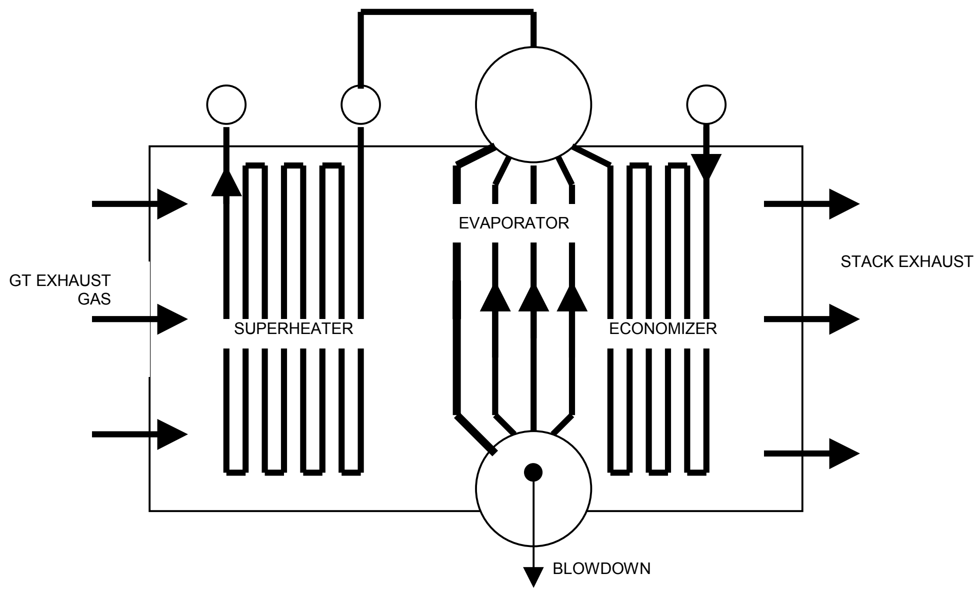

Figure #7 Drum -Type HRSG

For a fixed gas turbine load the OTSGô can operate at part load conditions without the requirement for gas or steam bypassing. By throttling back the feedwater flow to the OTSGô and desuperheating at the outlet header, the OTSGô can adapt to wide load swings. A base load transient is shown in Figure 8. Even with an instantaneous feedwater flow transient of 63 klb/hr to 73 klb/hr, steam temperature is maintained.

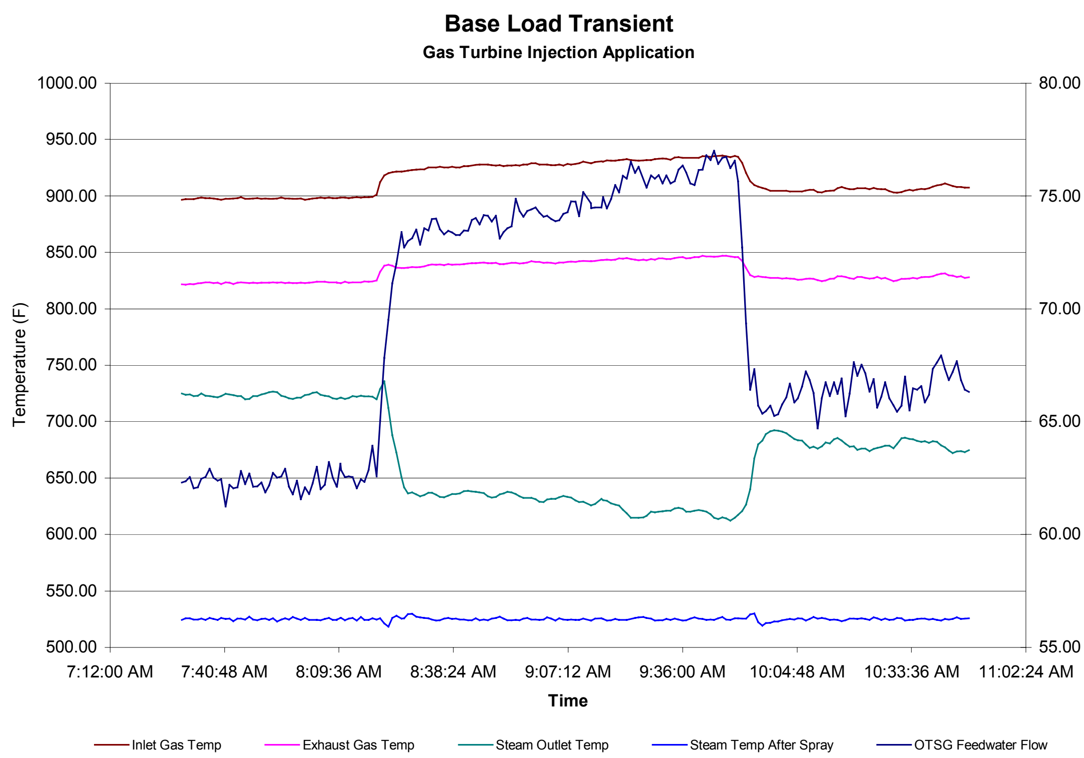

Figure #8 Base Load Transient

c) Dry Running

The OTSGô can be designed for dry running. Dry running refers to operation of the OTSGô without any water/steam flow inside the tubing allowing tremendous operational flexibility. Should steam injection not be required during certain times of the year, the OTSGô can be run dry without a gas bypass stack and damper. Conventional HRSGs use carbon steel as the tube material. Carbon steel loses strength at elevated temperatures making bypass stacks and diverter valves necessary to prevent the hot exhaust from damaging the tubes during dry running conditions. The elimination of the bypass stack and diverter valve, together with the systemís modular design, results in the OTSGô being up to 60 percent smaller and lighter than a comparable HRSG. This makes the OTSGô very attractive for projects that have size and weight restrictions, such as retrofit projects applications.

Tube material selection and operational guidelines will depend on the maximum gas temperature expected during dry running. While gas temperatures up to 1000 F (538 C) can easily be accommodated without any restrictions on operating procedures, gas temperatures up to 1500 F (816 C) can be accommodated with modifications to the materials of construction and limits on minimum feedwater temperatures entering the unit. Figure #9 indicates the steam injection OTSGô dry running temperatures to date.

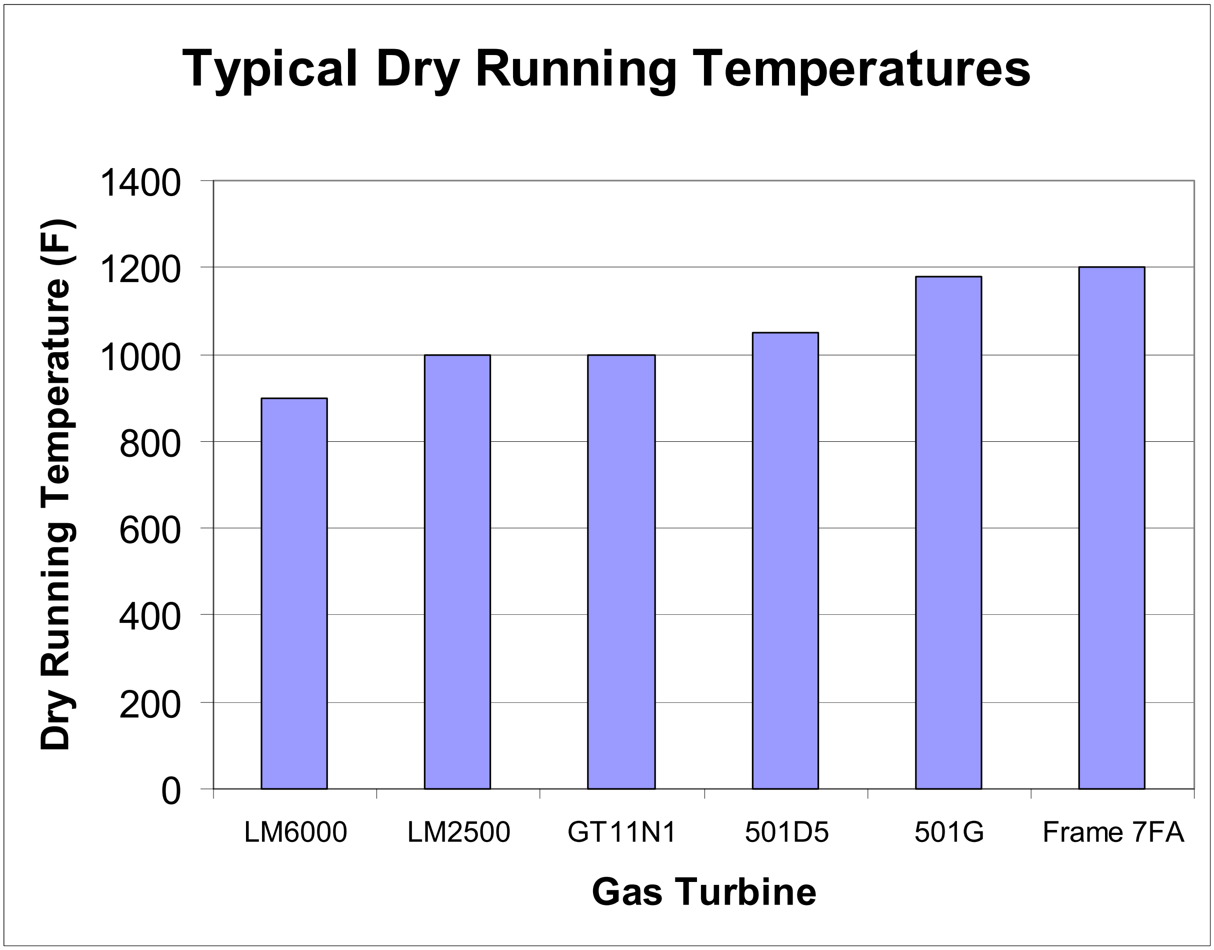

Figure # 9 Typical Dry Running Temperatures for Steam Injection Applications

d) NO_x Reduction

If NO_x emissions are a concern for current plant operation, steam injection can be used to reduce these levels. NO_x reductions from 162 ppmvd to 25 ppmvd are possible on some natural gas fired turbines with reductions from 279 ppmvd to 42 ppmvd possible on some distillate fired gas turbines. Placing an SCR (Selective Catalytic Reduction) into the system will reduce these emissions even further. Figure #10 indicates typical NO_x reduction levels for steam injection and SCR processes.

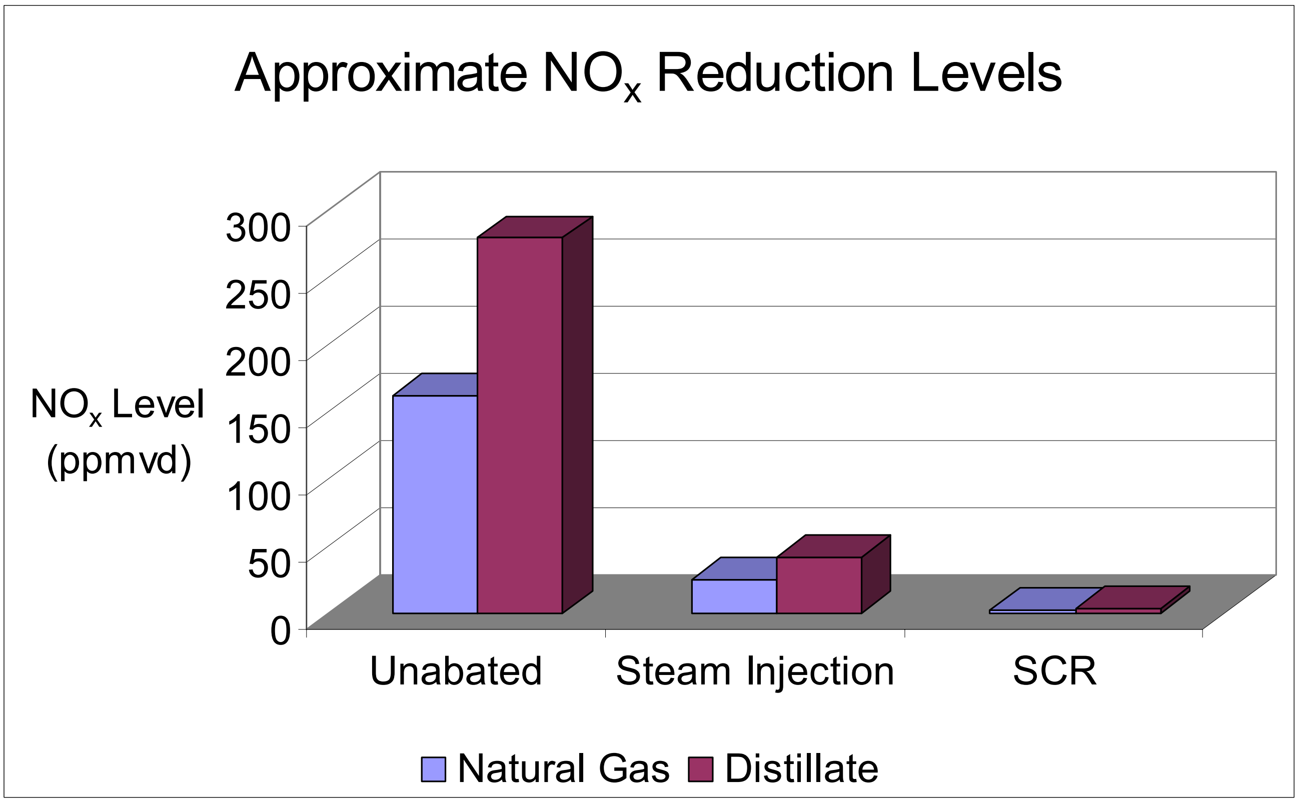

Figure #10 Approximate NOx reduction levels

Typical medium temperature SCR catalyst maximum continuous operating temperature is 800∝F with short temperature excursions up to approximately 900∝F. Placing the SCR catalyst downstream of the OTSGô will result in acceptable gas temperatures for NO_x reduction.

Should a high temperature SCR catalyst be placed upstream of the OTSG, all of the materials of construction of the OTSGô are very resistant to the corrosive effects of sulphuric acid, ammonium sulfate, ammonium bisulphate and ammonium hydroxide. Should deposits form, it is possible to remove the corrosive substances through dry running of the OTSGô.

A series of tests were conducted on OTSGsô   in the early 1980ís. Following soot fouling tests in which soot was accumulated on the cold section of the OTSGô , cleaning tests were completed. The cleaning tests involved running the OTSGô   at elevated gas temperatures without feedwater flowing through the OTSGô . Heat transfer performance was fully recovered by performing a dry boiler burnoff at 900 F for 100 minutes. Similar tests have been completed in an attempt to remove the corrosive products associated with SCR operation (ammonium sulphate). Dry running at gas temperatures approaching 900 F followed by compressed air blasting is also successful at removing the deposits associated with SCR operation.

e) Availability of Space

Figure #4 and #6 previously show typical OTSGô   steam/water flow paths. Any orientation can be configured, since gravity forces are not used in the design. Water flow can horizontal with exhaust gases vertically upward, or water flow can be vertical with a horizontal gas flow path. All of these configurations have been installed and tested.

Footprint is an important factor to consider when designing OTSGsô   for existing sites that have a fixed envelope of space available. In Figure #11 you will find a comparison between the overall size of an LM6000 40MW OTSGô   to that of a comparable LM6000 40MW HRSG. The footprint of the OTSGô   in the foreground is significantly smaller than that of the HRSG in the background.

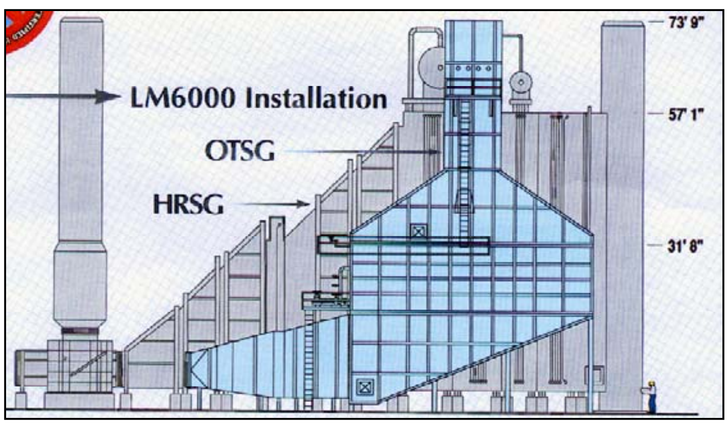

Figure 11 - Plan View and Footprint comparison of a LM6000 OTSGô   to a HRSG. Both units are approximately 5 m at their widest point.

Space savings for horizontal gas flow applications can be even more significant. The footprint impact can be eliminated on a steam injected application with a vertical tube OTSGô as the OTSGô is inserted into the existing duct. A typical installation is shown in Figure #12.

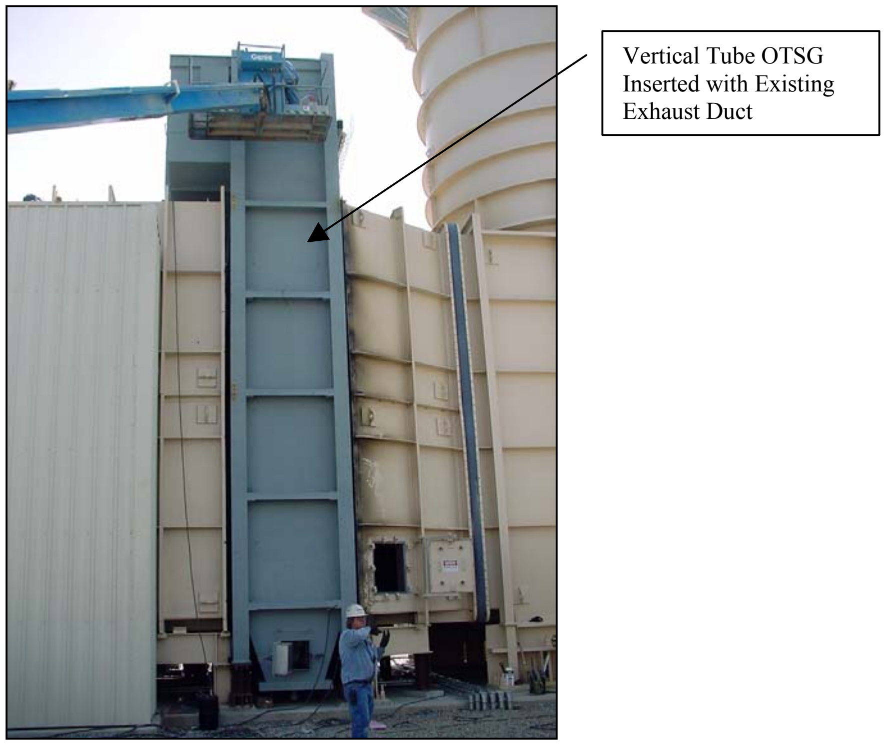

Figure #12 Steam Injected OTSGô
Frame 7FA Application

All OTSGsô supplied to date for steam injection applications have been shipped to site as shop hydrotested modules. The only field connections remaining are the feedwater piping, steam piping, vents and drains as required. The OTSGô in Figure #12 consists of two modules in width with approximate dimensions of 12 feet wide x 39 feet high x 8 feet deep in order to meet all the steam injection requirements.

f) Erection Sequence

The erection benefit is one of the major factors considered when owners, operators or developers consider OTSGsô. The standard OTSGô designed by IST and used in the more traditional vertical exhaust flow applications are composed of usually 5 components including the inlet duct, plenum, steam pressure part module(s), hood and stack. The erection span for a typical LM6000 sized OTSGô is less than 2000 labour hours (3 to 4 weeks). This leads to tremendous savings over the conventional drum-type HRSGs with the numerous pressure part modules, interconnecting piping, steam drums and site code weld requirements.

Steam injected OTSGsô have an even larger erection savings than the combined cycle and cogeneration applications. The OTSGô is usually a vertical tube, horizontal exhaust flow arrangement, which allows the OTSGô to be inserted between the existing gas turbine flange and the exhaust stack, consuming zero additional footprint. The erection span for the OTSGô installation and gas turbine modifications with all of the additional balance of plant equipment is usually limited to 800 to 1000 labour hours per system. This means the gas turbine can be out of service for less than 2 weeks.

The set of thumbnails in Figure #13 illustrates the simplicity of the OTSGô steam injected application installation process. The main steps are as follows:

1. Prep OTSGô Module
2. Connect crane with spreader beam top and bottom of pressure part module
3. Hoist module, lowering bottom end and raising top end
4. Lift module vertically and swing into position within existing exhaust duct
5. Slide OTSGô module into ducting

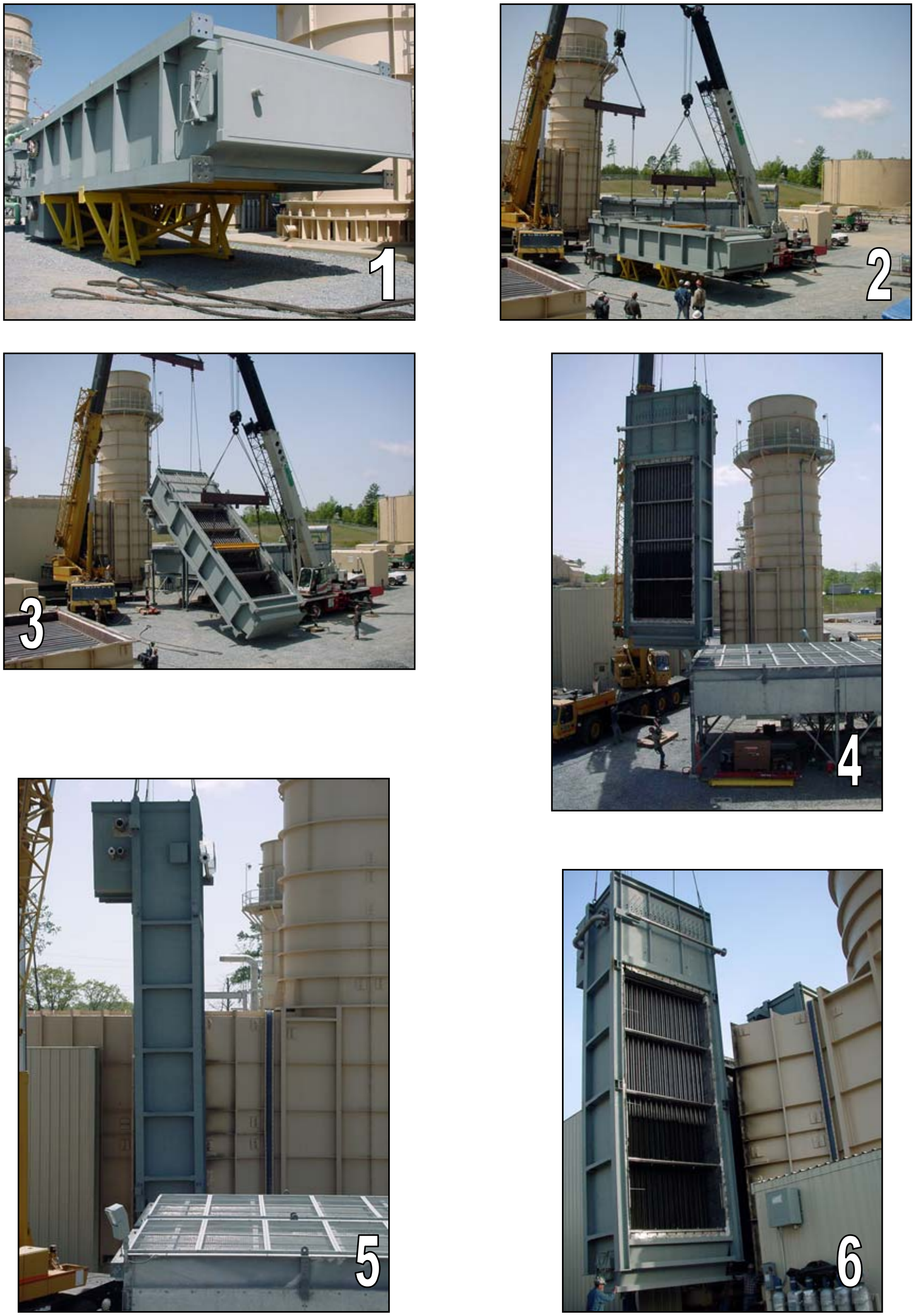

Figure #13 Steam Injection OTSGô   Erection Sequence

FINANCIAL JUSTIFICATION OF STEAM INJECTED OTSGô APPLICATIONS

The once through steam generator is generically referred to as an end user product as the OTSGô brings the biggest advantages to the owner, operator or developer of the power plant. The OTSGô has significant down stream advantages including low installation, operational and maintenance cost and extreme operational flexibility. These factors are quantified as significant financial advantages during the evaluation stage of steam injection retrofit projects.

However, with existing power plants the structure of the power purchase agreement (PPA) can effect the financial feasibility of retrofit steam injection applications on simple cycle gas turbines. Most PPAís have the ability to create additional revenue for the plant operators.

Increased revenue opportunities will be dependent on the structure of the PPA. Several schemes are summarized below:

1) PPA structured to create plant revenue for peak load power production (kW). Plant power production is not commercially capped and additional revenue can be made if excess power production (kW) is achieved. This type of PPA is referred to as a ***Flexible Production Payment*** structure.

$$PPA_{REVENUE}\ f(kW) = (kW_{\ PEAK}) + \underbrace{(kW_{\ PEAK})_{\ EXCESS}}_{\text{Steam Augmentation}}$$

2) PPA structured to create revenue based on continuous installed capacity (plant on or off), power production payment is based on availability of power (kW). Generally these type of PPAs also have an energy production factor, so the PPA payment is a function of total available power and the actual power being produced. This PPA is referred to as a ***Capacity and Energy Production Payment*** structure. If the PPA is not commercially capped (kW_{MAX}), then augmentation can increase revenue for both components of the payment.

$$PPA_{REVENUE}\ f(kW) = (kW_{\ CAPACITY} + kW_{\ ENERGY\ PRODUCTION}) + \underbrace{(kW_{\ CAPACITY} + kW_{\ ENERGY\ PRODUCTION})_{EXCESS}}_{\text{Steam Augmentation}}$$

3) PPA structure is fixed and no payment for excess power production, only on fixed power production (kW_{MAX}). Operation cost can be reduced due to the lower plant heat rate; for example, improved fuel economy on gas turbine at fixed power production (kW_{MAX}). This type of PPA is referred to as a ***Fixed and Capped Production Payment*** structure.

$$PPA_{REVENUE}\ f(kW) = (kW_{\ EFIXED\ ENRGY\ PRODUCTION}) + \underbrace{\text{Fuel Savings}}_{\text{Steam Augmentation}}$$

4) PPAs are also structured with various combinations of 1), 2), or 3) above.

Most PPAís have some ability to create additional revenue for the plant operators and as a minimum there will be some significant fuel savings. In order to quantify the financial justification of the plant we must define the required additional scope for the retrofit.

STIG Simple Cycle Application Description and Scope Requirement

A simple cycle plant would be composed of a gas turbine, inlet exhaust duct, silencer (if required), and exhaust stack. The balance of plant (BOP) would include a distributed control system or programmable logic controller, fuel supply skid, emissions monitoring equipment, and air intake filter house. The footprint would depend largely on the mechanical dimensions of the gas turbine, ducting required and layout arrangement.

The retrofit of a simple cycle application to a steam injection power augmentation cycle would require the addition of the OTSGô and additional BOP equipment and modification to the gas turbine, if steam injectors are not present. The extra equipment or service requirements would generally include the following:

- Steam injection control valves and automated drain valves supplied directly by GT manufacture.
- Upgrade of gas turbine controls to add steam injection.
- Gas turbine vendor startup service.
- Steam injection nozzles and piping internal to gas turbine. These are often included in simple cycle applications as standard equipment.
- Demineralized water treatment equipment, storage tank, and transfer pumps. Again this is sometimes existing at some sites.
- OSTGô pressure part module.
- OTSGô startup and commissioning services.
- Insulation and Lagging.
- Civil works and erection services.
- Freight
- Commercial Cost (legal, tax, financing, insurance, bonding, etc.).

The following performance is typical for a 2 x Frame 7FA steam injected application.

Gas Turbines	2 x 155 MW
Total Plant Output (regular)	310 MW
Steam Injection	118,400lb/hr m at 345 psia/700°F per OTSGô /GT (equivalent to 3.5% of the compressor air flow and a resulting power increase of 8.4%)
Heat Rate (without steam injection)	9630 Btu/kWhr
Heat Rate (with steam injection)	9270 Btu/kWhr

A significant increase in revenue can be achieved with this example for PPAs that are either a ***Flexible Production Payment*** structure or a ***Capacity and Energy Production Payment*** structure defined above. Significant fuel savings can also be achieved with the use of power augmentation. This is an alternative saving for clients who have a PPA that is a ***Fixed and Capped Production Payment*** as above. This saving would be in the form of fuel economy on the gas turbines. The client would regulate the power production for the plant at a fixed kW rate. The steam injection would augment the mass flow through the gas turbine and reduce the amount of fuel required to maintain the fixed kW plant production. The augmentation can be used year round at all ambient conditions. Utilizing the data above and typical fuel pricing, the fuel savings can be calculated on an hourly, daily, monthly or annual basis as shown in Table #1.

Fuel Savings Calculation			HEAT RATE = BTU/kWhr
Btu/kWhr current	9630	= FUEL / 310MW	
Btu/kWhr enhanced	9270	= FUEL / 310MW	
FUEL=	2985300000	Btu/hr	@ 9630Btu/kWh
	2985.3	MMBtu/hr	
FUEL=	2873700000	Btu/hr	@ 9270Btu/kWh
	2873.7	MMBtu/hr	
The Difference	111.6	MMBtu/hr	
Fuel price	3.08	$/MMBtu	
Saving per:	Hr	1	$ 344
	Day	1	$ 8,249
	Days	30	$ 247,484
	1 Year	365	$ 3,011,057

Table 1. Fuel Savings Calculation

There are many factors that must be considered when evaluating the increased revenue and payback period for a steam injection application. The factors that need to be evaluated are the type of PPA, the Capital Expenditure (Capex), Operational Expenditure (Opex), Construction Cost, PPA Escalation Factors, Fuel Price Escalation, Financing Requirements, Water Supply Cost, Taxes, Insurance, Bonding and Administration Cost.

Depending on the above factors the payback period can be calculated. Typical payback periods range from 3 months to 3 years due to variables such as a higher steam injection rate, higher capacity payment and energy production payment and are very much plant specific.

FINANCING ALTERNATIVES FOR OTSGô STEAM INJECTION APPLICATIONS

In todayís energy market there is less room for allowable risk. Many large US based power production companies are retrenching and freezing new capital investment until the US market re-surges (which may be a longer period than many initially expected) or until they diversify their business opportunities into foreign growth markets, such as Asia and Europe and the Middle East. IST can offer a solution, involving a debt service structure that requires zero capital investment on the part of the owners, operators and/or developers. The debt service is a financing structure, which pays down the debt, and creates revenue for the participating groups. The group can involve such parties as the plant Owner and Operator, the gas turbine manufacturer, the OTSGô supplier (IST), the Utility and the Gas Company. The financial structure should be constructed once the fixed commercial variables are defined. Then the equipment cost must be quantified and the other variables negotiated. The debt service vehicle would permit the purchase of the retrofit project with no capital outlay on the part of the client. Members of the group could also contribute equity to reduce the loan amount. The external equity can come from a financial partner who participates in the cash flow returns or from one of the defined participating group members.

CONCLUSIONS

In todayís power marketplace increasing the efficiency of existing powerplants can be a very attractive opportunity. Power augmentation of new or existing simple cycle gas turbines is possible with the OTSGô. The design considerations of the OTSGô allow for increased power production, greatly reduced NO_x levels, increased revenue with a low capital outlay, typical payback of 3 months to 3 years and no limitations in current plant operating philosophies.

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