EPIC
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HEAT RECOVERY STEAM GENERATORS

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Innovative Steam Technologies (IST) designs and manufactures once-through heat recovery steam generators, which are used in the power generation sector. The Once-Through Steam Generators (OTSGs) are simple, continuous flow boilers that convert feedwater into high purity steam. The OTSGs are well suited technically and economically for combined cycle, cogeneration and gas turbine steam injection applications.

The OTSG has many notable features. A very significant one is full dry running capability on most applications, which eliminates the need for a bypass stack and damper. The OTSG requires significantly fewer components than a typical drum-type HRSG. The installation is accomplished faster and at a much lower cost due to the relatively high amount of factory assembly and testing that is completed prior to shipment. The system has a once through flow path; therefore no steam drums or blowdown systems are required. Demonstrating a significant improvement over the natural circulation and forced circulation drum-type units, it offers proven experience and cost savings benefits.

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1.0 Basic Heat Recovery and HRSG Concepts

A Heat Recovery Steam Generator (HRSG) is the standard term used for a steam generator producing steam by cooling hot gases. HRSGs can recover energy from any waste-gas stream, such as incinerator gases, furnace effluents, reciprocating engine exhaust or more commonly from gas turbine exhaust. Waste heat is a very desirable energy source as it has a significant amount of usable energy and it is basically cost-free. Prime candidates for HRSGs are plants where process streams produce high temperature gases, which may be harnessed to produce steam or to heat water. Even if the steam is not required for process, it may pay to produce the steam for sale to other industrial firms or used to produce electricity for in-plant use or sale to a utility.

Originally developed as sources for waste heat recovery not requiring fuel consumption, HRSGs have become sources of energy themselves, as they are often required to produce a constant supply of steam regardless of the amount of waste gas available.

Today, the HRSG is the critical link between the gas turbine and steam turbine in combined cycle and cogeneration plants. Owners and Owner's Engineers are now placing more design and optimization effort on the HRSG.

1.1 HRSG Design

The basic HRSG consists of an economizer, evaporator and superheater. These are tubular type heat exchangers with the working fluid (water/steam) on the inside and the exhaust gas on the outside. Because the exhaust gas from a gas turbine is very clean, it is possible to use finned tubes to improve heat transfer and reduce the HRSG size. The type and size of fin used depends on various design parameters including exhaust gas constituents and temperature.

The design philosophy is to exchange heat from the exhaust gas to the fluid at the highest temperature difference available. This is accomplished by making the exhaust gas and the fluid (steam/water) temperature gradients as nearly parallel to each other as possible. This is illustrated in Figure 1.

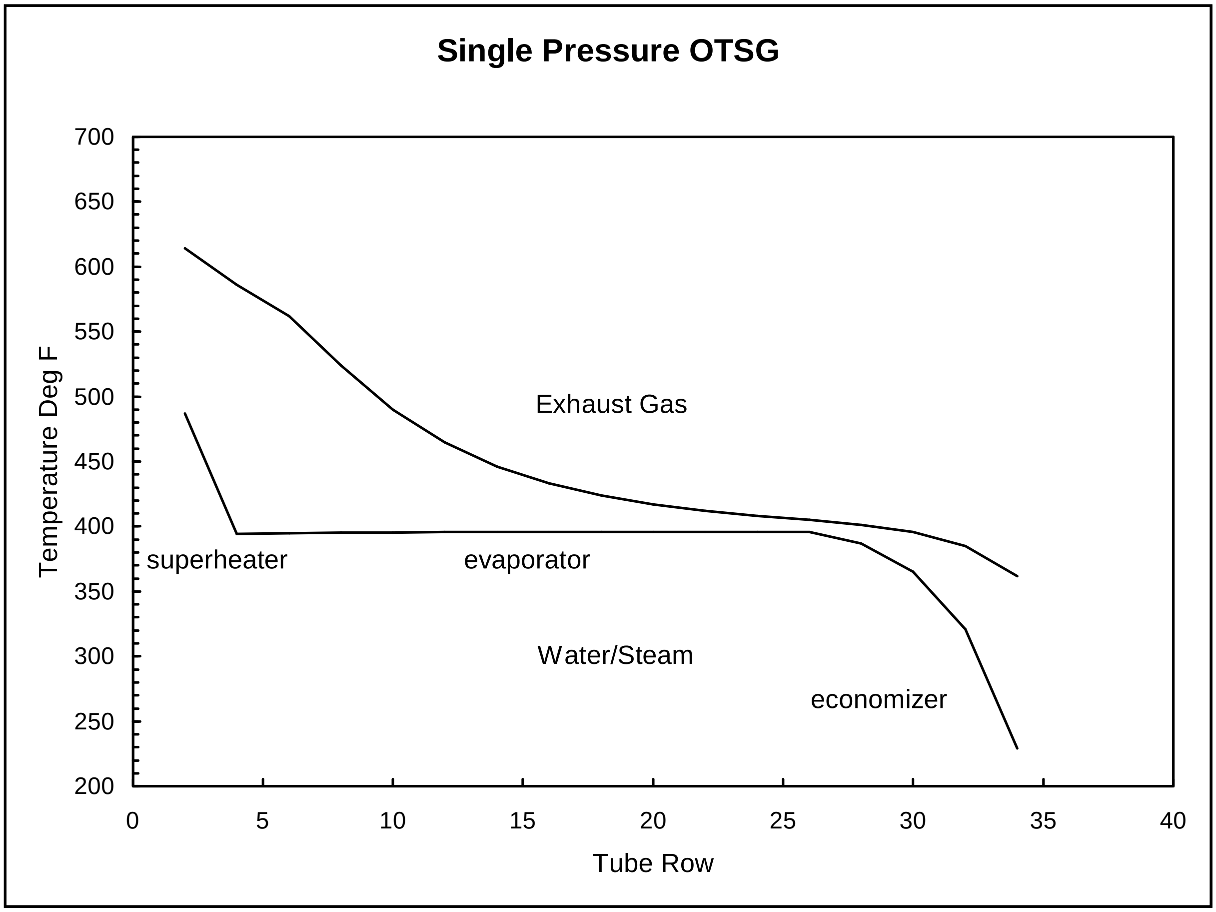


Figure 1 – Exhaust Gas and Water/Steam Diagram for a Single Pressure OTSG

The design parameters required by HRSG manufacturers can be summarized as follows:

a) Gas Turbine Model
b) Gas Turbine Exhaust Flow
c) Gas Turbine Exhaust Temperature
d) Gas Turbine Exhaust Constituents
   The most important constituent is water (H_2O) as a higher moisture content increases gas enthalpy (more heat available) and results in higher heat transfer coefficient.
e) Fuel Gas Composition
   This is required for supplementary-fired units.
f) Feedwater Temperature
   Has a minor influence on steam output but is vital in selection of tube and fin materials in the HRSG cold end.
g) Steam Pressure(s)
h) Steam Temperature(s)
i) Steam Quality
j) Required Steam Flow(s)
k) Allowable Gas Side Pressure Drop
l) Blow Down Rate
   The discharging of saturated water to maintain the required level of total dissolved solids (TDS) in the drum water. Not applicable to Once Through Steam Generators.

The calculated parameters include:

a) HRSG geometry and heat transfer surface area
b) Heat Transfer Coefficients
c) Actual Steam Flow
d) Thermal Losses
   All HRSGs lose heat to atmosphere from the surface.
e) Actual Gas Side Pressure Drop
   An additional gas side pressure drop of 4 inches WG results in approximately 1% decline in the electrical power output of the gas turbine.

1.2 Common HRSG Terms

a) Pinch Point

Pinch point refers to the difference between the gas temperature leaving the evaporator section of the tube bundle and the saturation temperature corresponding to the steam pressure in that section (Figure 2). Lowering the pinch point results in an increase in the total heat recovered in that section. To lower the pinch point, the HRSG requires additional heating surface area to be added. This results in an increased capital cost, and a subsequent increase in gas side pressure drop.

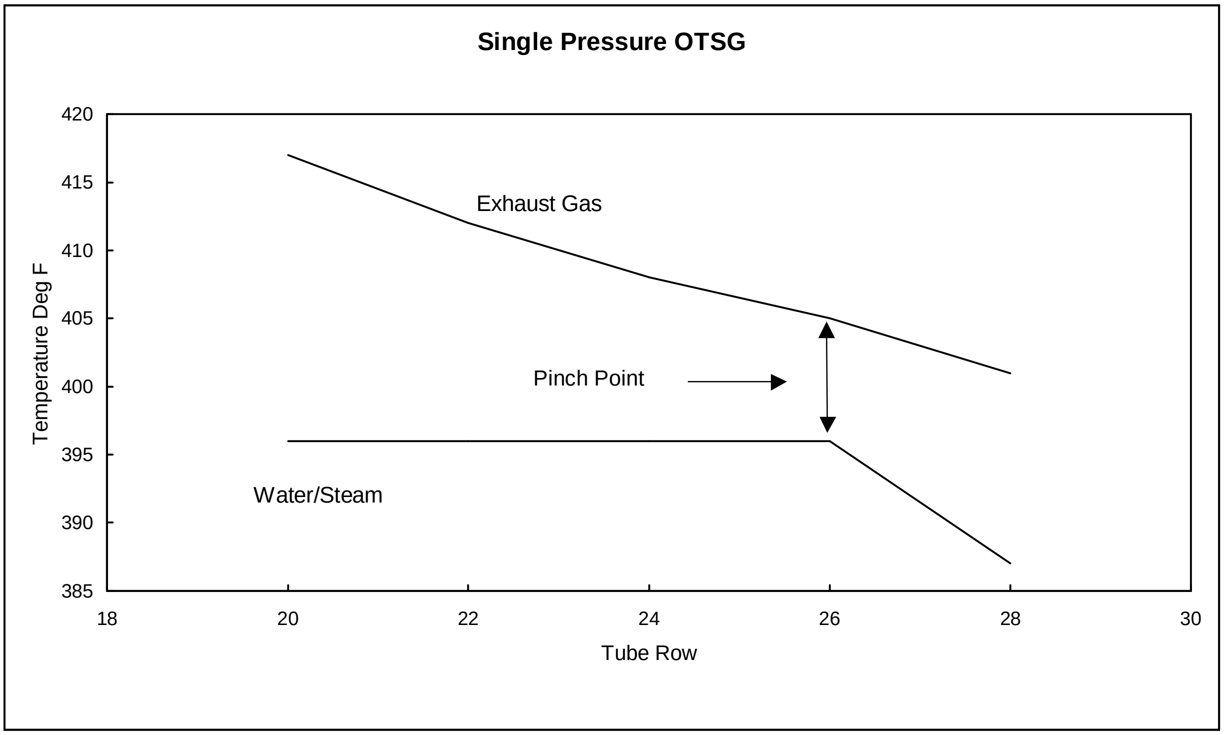


Figure 2 – Pinch Point Diagram

The amount of surface that is required to reduce the pinch point increases dramatically as the pinch point drops. As Figure 3 indicates, moving from a pinch point of 25 F to 10 F requires approximately 32% additional surface. For unfired HRSGs, the optimum pinch point ranges from 10 F to 30 F. For the HRSG to be optimized the plant designer must determine the value of steam produced ($/lb) so that the HRSG performance and cost can be optimized.

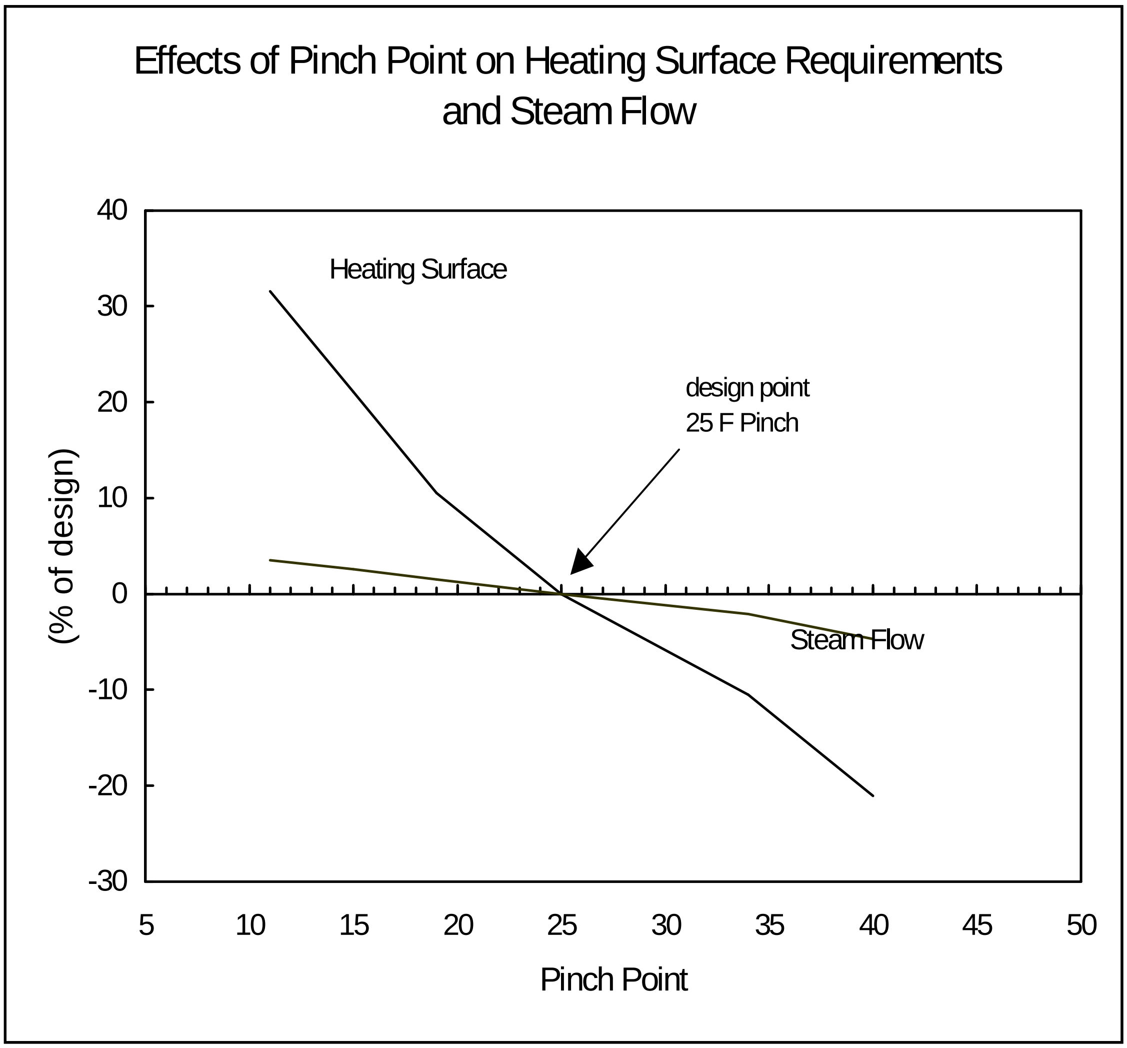


Figure 3 – Effects of Increased Pinch Point

b) Approach Temperature

The approach temperature is the difference between the water temperature leaving the economizer and the saturation temperature of the evaporator. Lowering the approach temperature results in more steam production but also requires more heat exchange surface and a subsequent increase in cost and gas side pressure drop. For natural circulation and forced circulation HRSGs, it is desirable to maintain a minimum approach temperature to prevent generating steam in the economizer. Steaming in the economizer should be avoided to prevent steam plugs, flow instability and tube wall temperature cycling. Typical approach temperatures are approximately 25 F.

Approach temperatures do not exist for Once-Through Steam Generators, as there is no distinct boundary between the economizer and evaporator sections.

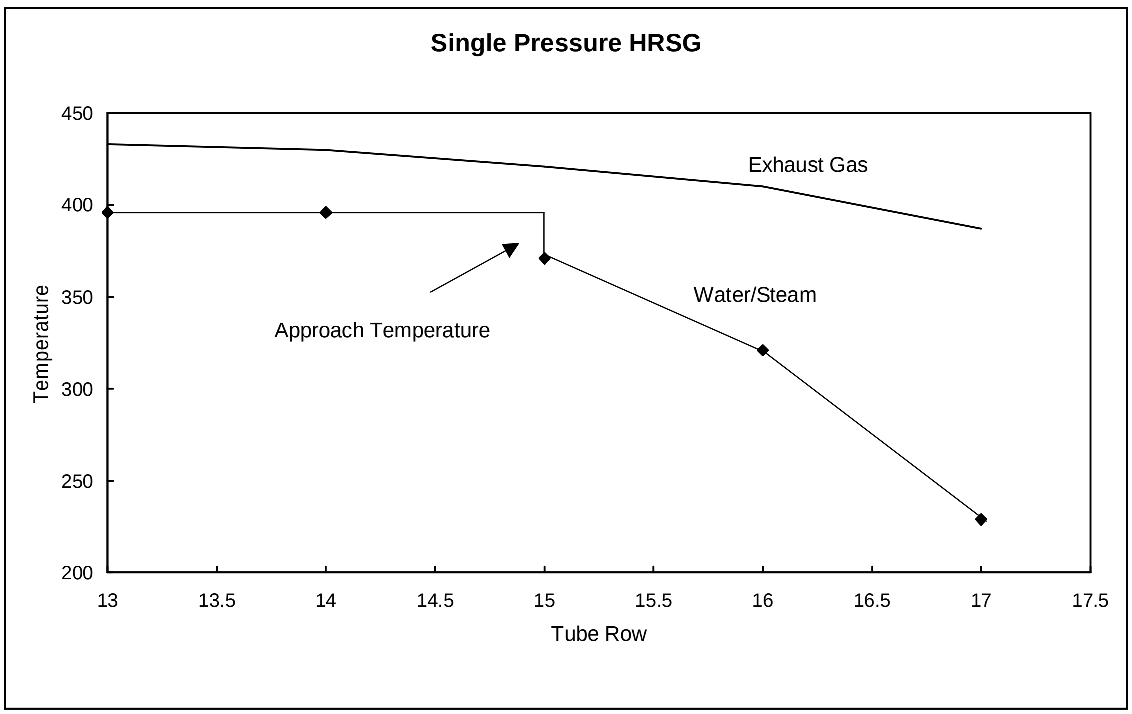


Figure 4 – Approach Temperature Diagram

2.0 HRSG Components

2.1 Preheaters

Preheaters are usually gas to liquid heat exchangers used to recover additional energy from the exhaust gases. Typically preheaters are located at the cold end of the HRSG to absorb low-grade energy from the exhaust gas. The most common application is to preheat condensate prior to entry into the deaerator as shown in Figure 5. This reduces the amount of steam required for deaeration.

Due to the low gas and fluid temperatures associated with preheaters, there are concerns related to water dewpoint corrosion and acid dewpoint corrosion.

a) Water dewpoint corrosion can occur when the preheater metal temperatures are below the water dewpoint. Operation of sections at this condition will lead to accelerated corrosion of carbon steel and stainless steel heat transfer surfaces (tubes and/or fins). With todays steam and water injected gas turbines, water dewpoint corrosion has become more of a concern.

b) Acid dewpoint corrosion occurs when fuels fired contain trace quantities of sulfur. This forms sulfur dioxide (SO_2) some of which converts to sulfur trioxide (SO_3). The SO_3 combines with water vapour in the exhaust gas to form sulfuric acid, which creates the potential for localized corrosion in colder sections of the preheater. Materials must be carefully selected to operate in this environment.

To avoid this corrosion in the HRSG, it is also possible to incorporate external water to water preheaters. The boiler feedwater leaving the deaerator can be used to preheat the incoming makeup water. This system is attractive if the water temperature ranges from 40 F to 60 F as the size of the heat exchanger can be kept small due to the high temperature differences. If the makeup water enters the HRSG at a temperature close to the deaerator temperature (190 F to 215 F) this option may not be justified.

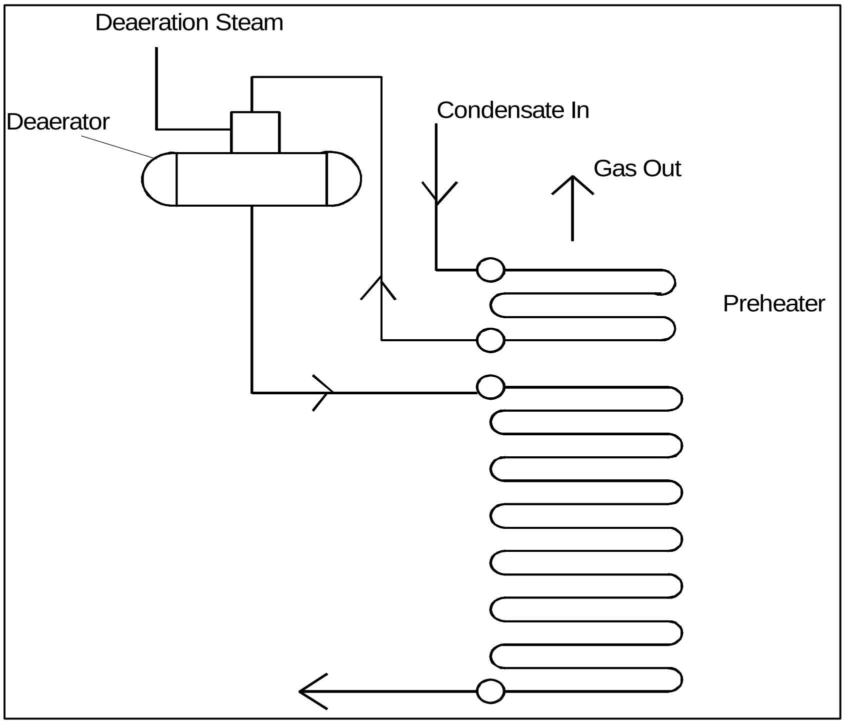


Figure 5 – Preheater Located in HRSG

2.2 Economizers

Economizers are gas to water heat exchangers used to preheat the boiler feedwater prior to entry to the evaporator. There may also be some corrosion concerns in this section, depending on the entering feedwater temperature.

The economizer in a single pressure OTSG will be located directly upstream of the evaporator section. In a multiple pressure HSRG, the economizer section can be split in many sections upstream of the evaporator for the most economical arrangement.

2.3 Evaporators

The evaporator or boiler bank is a gas to wet steam heat exchanger that generates saturated steam from the boiler feedwater. The evaporator is placed between the economizer and superheater sections.

The water/ steam mixture leaves the evaporator and enters a steam drum through pipes called risers. The steam drum is a cylindrical pressure vessel mounted at the top of the boiler. Once inside the drum, mechanical devices such as cyclones and/or screens separate the water/steam mixture. The dry steam leaves the drum through pipes leading to the superheater. Steam free water leaves the steam drum through pipes (or tubes) called downcomers and is recirculated through the evaporator section. It is important that dry steam enter the superheater because water droplets contain dissolved solids, which will deposit on the inside of the superheater tubes. Deposits on the inside of superheater tubes will cause tube metal temperatures to rise, and may eventually lead to tube failure.

2.4 Superheaters

Superheaters are gas to dry steam heat exchangers that generate superheated steam. The superheater can consist of either a single heat exchanger module or multiple heat exchanger modules. Multiple superheaters usually have some type of steam temperature control between them to prevent excessive metal temperatures in the final pass and to minimize the possibility of water carryover to steam turbines.

3.0 Saturated Steam vs. Superheated Steam HRSG's

3.1 Saturated Steam HRSG

When water boils, both it and steam are at the same temperature, known as the saturation temperature. For each boiling pressure, there is only one saturation temperature. Therefore, during the boiling process, temperature remains constant, even though heat is being added. The saturated steam HRSG will consist of only an economizer to preheat the feedwater and an evaporator to produce saturated steam.

3.2 Superheated Steam HRSG

As long as steam and water are in contact, their temperatures will remain the same. To raise the temperature of the steam, it must be superheated by raising the temperature of the steam out of contact with the water. The saturated steam produced in the evaporator is sent to a separate heat exchanger referred to as a superheater.

4.0 Single Pressure vs. Multiple Pressure HRSGs

4.1 Single Pressure HRSG

The simplest design is the single pressure, unfired HRSG. The superheater, evaporator and economizer have to be placed in descending fluid temperature along the gas path. The saturation temperature of the evaporator limits the amount of heat that can be absorbed from the exhaust gas. The exhaust gas temperature leaving the evaporator cannot be lowered below the steam saturation temperature. This is illustrated in Figure 6.

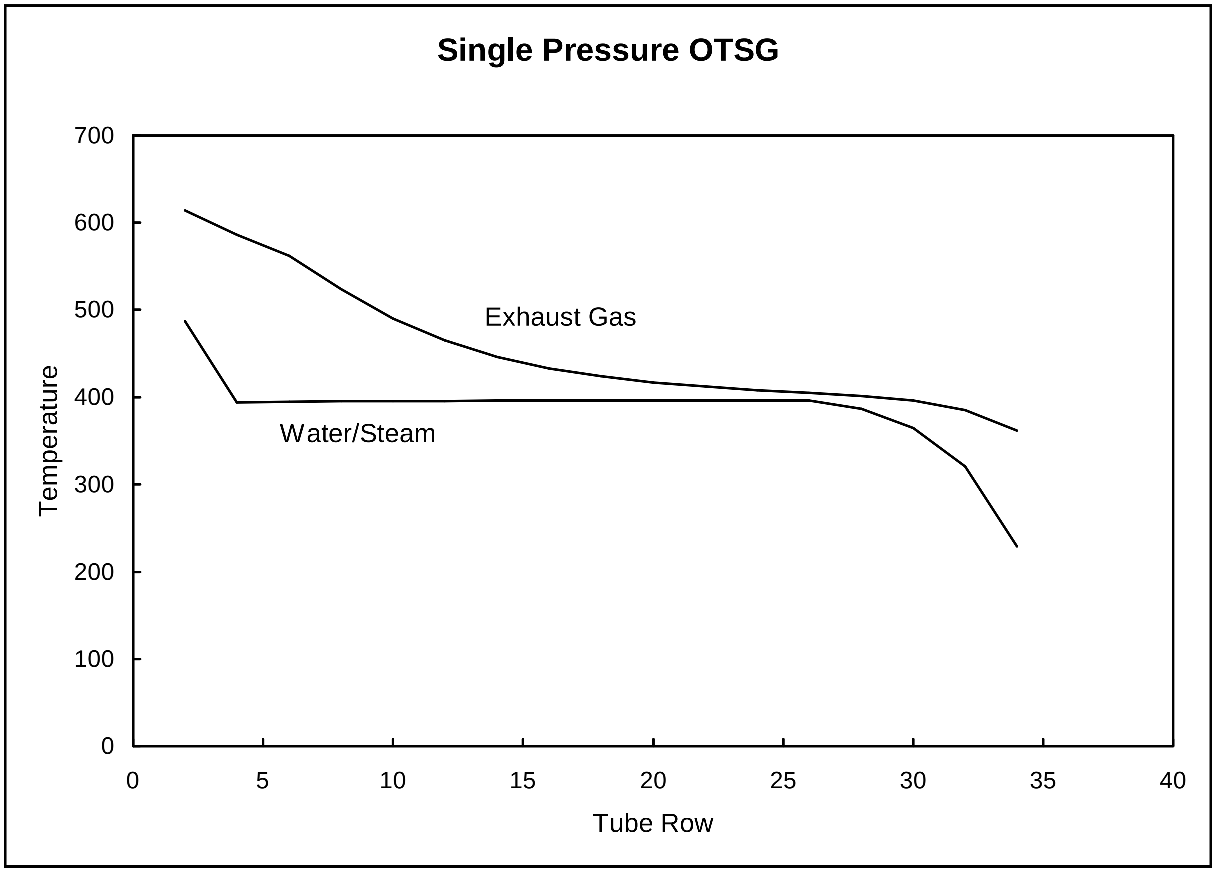


Figure 6 – Single Pressure OTSG

4.2 Multiple Pressure HRSG

Adding additional pressure levels in the HRSG can increase the amount of heat that can be recovered from the exhaust gas. As the saturation temperatures are lower at successive pressures, the stack temperature can be lowered. The multiple pressure scenarios are useful and economical if steam at the various pressure levels can be utilized for applications such as multiple stage steam turbines, deaeration, feedwater preheating or gas turbine steam injection.

In a multiple pressure HRSG, the general location of economizer, evaporator and superheater is maintained, but various sections may be interchanged so that a nearly parallel relation between the temperature gradients is achieved. This is illustrated in Figure 7.

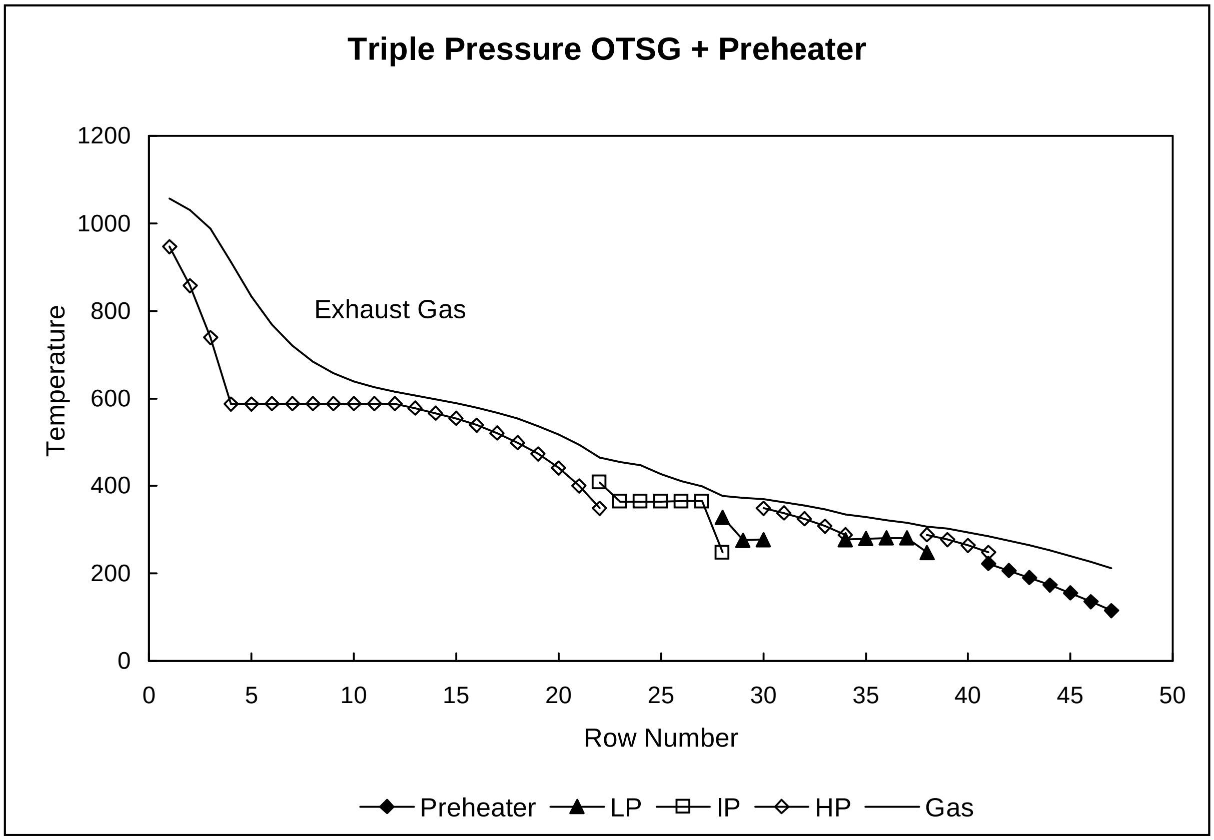


Figure 7 – Multiple Pressure OTSG

5.0 HRSG Types

5.1 Natural Circulation HRSG

In a natural circulation HRSG, gas turbine exhaust flows past vertical tubes. Circulation is maintained by the density difference between the saturated feedwater supplied through a downcomer to the lower drum or evaporator tubes and the water/steam mixture flowing to the steam drum through risers.

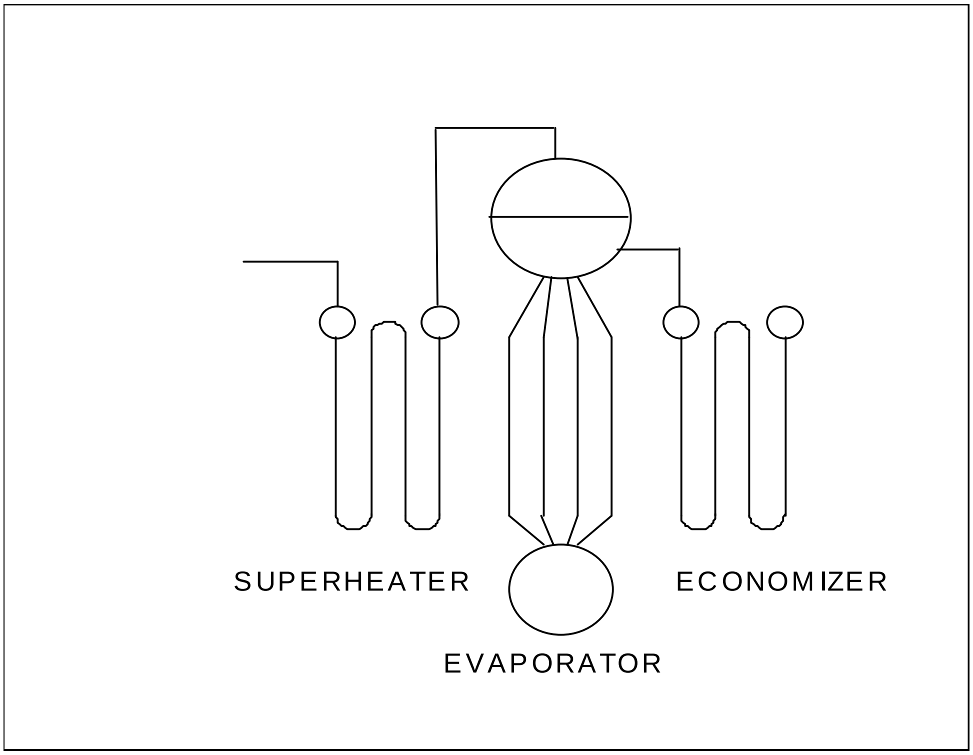


Figure 8 – Natural Circulation HRSG

Natural circulation HRSGs are available in alternative designs in order to achieve the most economical option. The options are as follows:

a) Integral steam drum

This type of HRSG is supplied for gas turbine sizes approximately 50 MW and lower. The HRSG incorporates internal downcomers to minimize the length of the steam drum. The HRSG boiler bank section can be shipped to site in a single component, minimizing field erection.

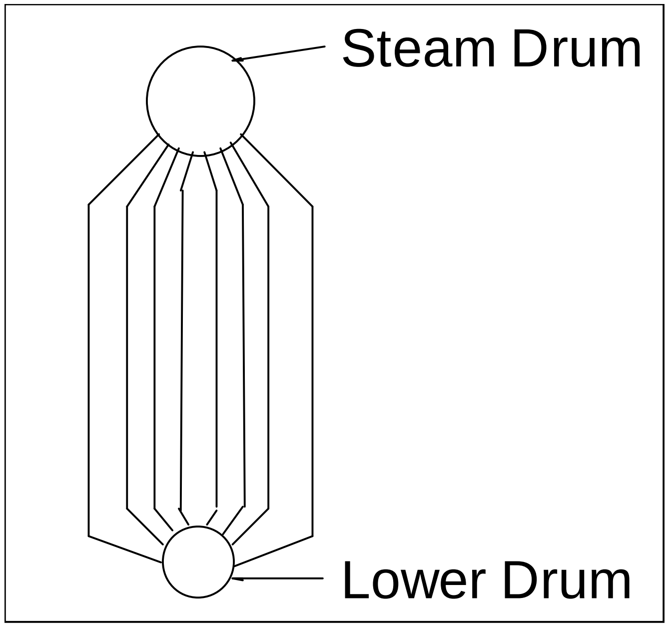


Figure 9 – Integral Steam Drum

b) Separate steam drum

When the length of the steam drum is beyond shipping clearances, a separate steam drum is sent to site and connected in the field to the evaporator section. The evaporator section is composed of multiple modules made of top and bottom headers with tube rows connected to them. The evaporator section must be connected to the steam drum with risers to release steam and with downcomers to be fed with water. These HRSGs are typically supplied for gas turbine sizes in excess of 50 MW. Although supply prices are lower than integral drum designs, erection costs are much higher due to the amount of interconnecting piping.

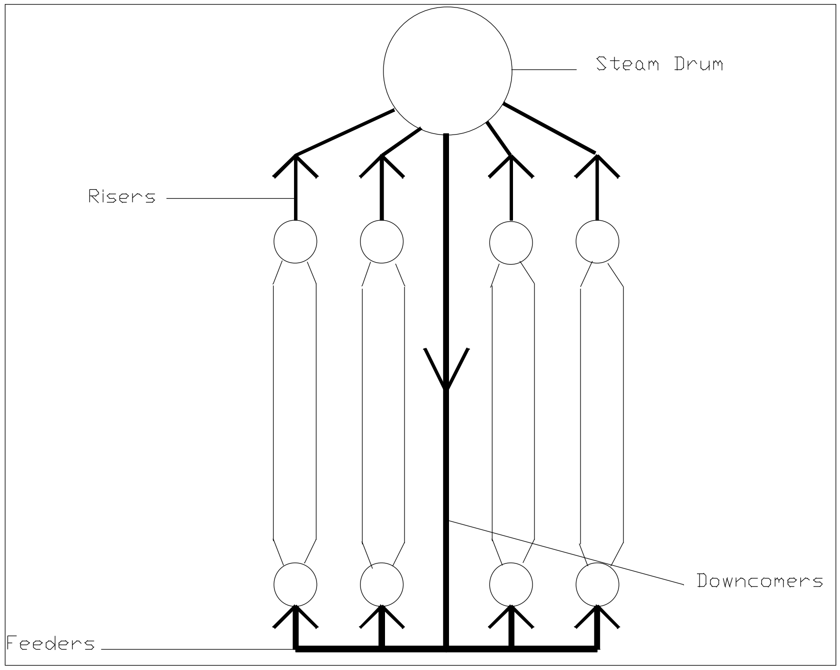


Figure 10 - Separate Steam Drum

Natural circulation HRSGs tend to be simpler and less expensive to operate than forced circulation HRSGs due to the absence of circulation pumps.

5.2 Forced Circulation HRSG

In a forced circulation HRSG, the gas turbine exhaust flows vertically past horizontal tubes. Circulation in the evaporator section is maintained with a circulation pump. Circulating pumps circulate the steam water mixture through the tubes of the evaporator to and from the drum.

Recirculation pumps must be located at a level far enough below the steam drum so that the static head acting on the water inlet to the pump is sufficient to avoid difficulties with cavitation.

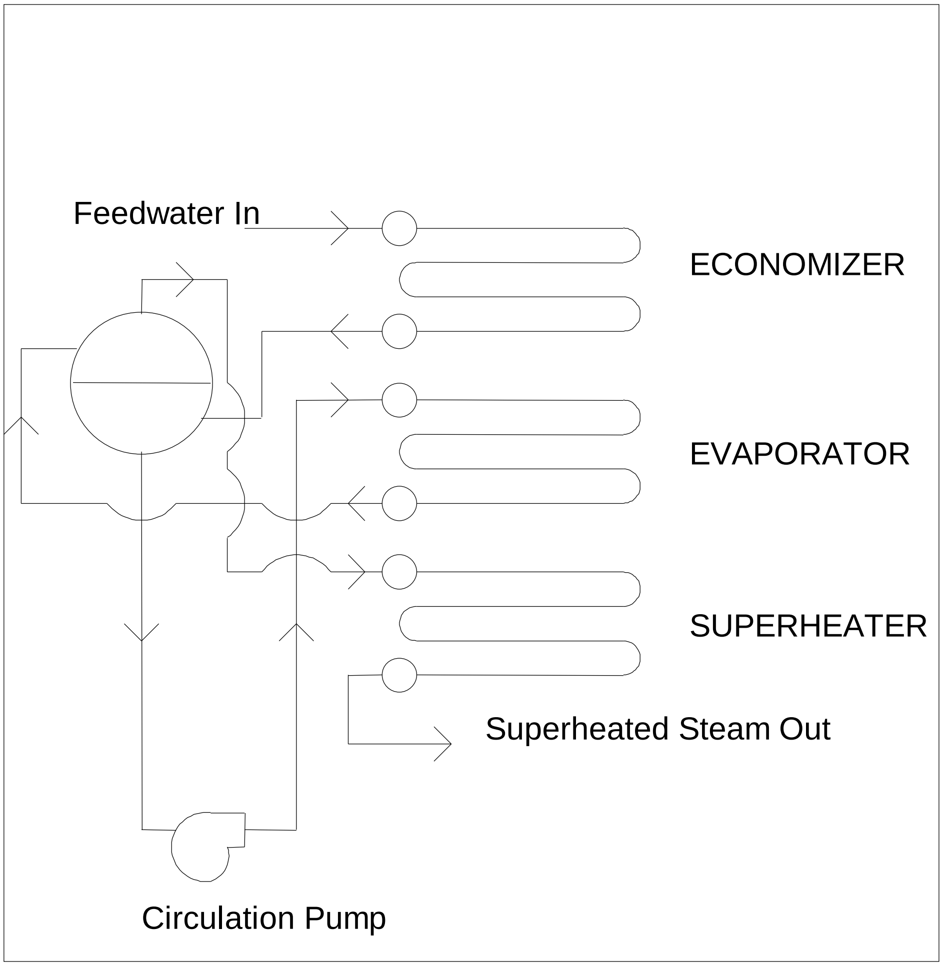


Figure 11 – Forced Circulation HRSG

Traditionally, most HRSGs in Europe have been specified as forced circulation. The advantages of forced circulation HRSGs over natural circulation HRSGs are smaller footprint, natural drainability and decreased startup times. The difference in cold start up times is not large due to the fact that most of the start up time is spent heating up the metal and the evaporator water (common to both designs). There is a small reduction in hot restarts due to the circulation of water in forced circulation designs, but is not considered significant.

5.3 Once-through steam generator (OTSG)

In a once-through steam generator, the gas turbine exhaust flows past vertical and/or horizontal tubes. The OTSG is basically a continuous tube in which preheating, boiling and superheating occur. The evaporator section is free to move throughout the bundle depending on the operational load. OTSGs eliminate the need for the steam drums, level controls, blowdown and recirculation systems. Startup times can be greatly reduced due to the absence of thick walled pressure vessels and the steam drum water inventory, which requires heating.

The OTSG has all the benefits of the forced circulation HRSG with the added benefits of no circulation pumps and decreased start up times.

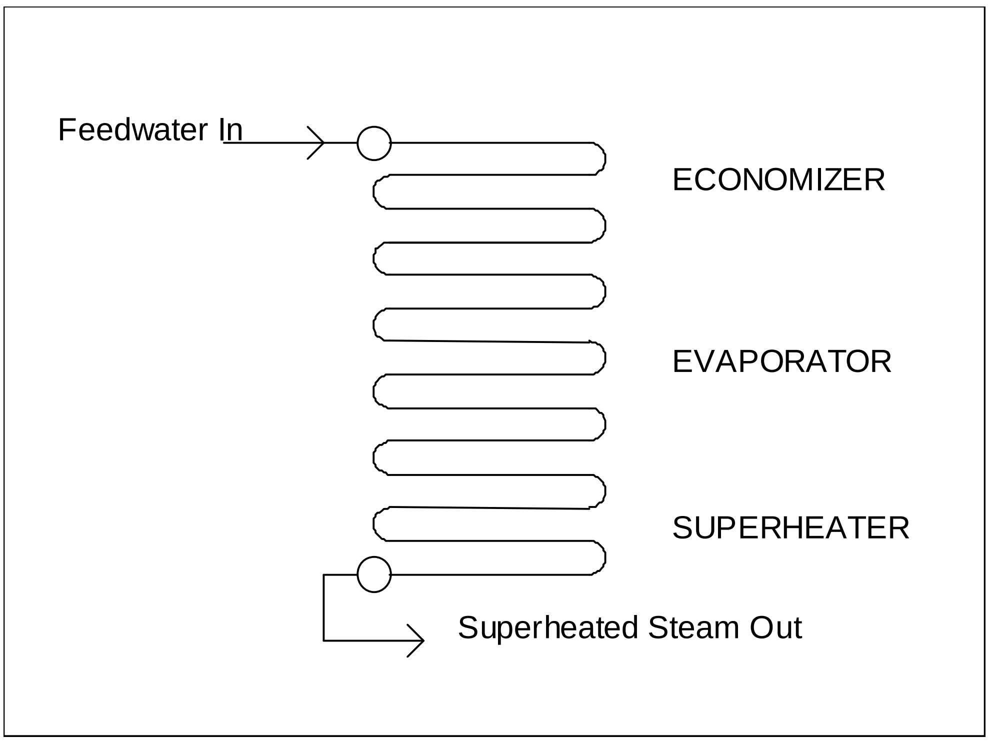


Figure 12 – Once Through Steam Generator (OTSG)

6.0 Unfired HRSG vs. Fired HRSG

6.1 Unfired HRSG

If the exhaust energy leaving the gas turbine is sufficient to produce enough steam to meet requirements, an unfired HRSG is selected. Depending on the exhaust gases, steam conditions can range from 150 psig to 1500 psig and from saturated steam temperature to 1000 F superheated steam. The final steam temperature can be up to approximately 50 F below the turbine exhaust gas temperature with typical gas temperatures leaving the gas turbine from 850 F to 1200 F.

The performance of unfired HRSGs are driven by the gas turbine operating condition and cannot easily provide steam for pressure control.

6.2 Supplementary Firing

The primary purpose of supplementary firing is to add heat to the process gas stream. Supplementary fired HRSGs are required when:

a) The gas turbine exhaust changes due to changes in ambient temperature and the steam requirements cannot be met.
b) The gas turbine exhaust changes due to load changes and the steam requirements cannot be met.
c) The steam demand increases without any change in the gas turbine exhaust.
d) The gas turbine is completely down but steam is still needed. This is referred to as fresh air firing and is described below.
e) When the desired steam flow or final steam temperature cannot be achieved with the available heat from the gas turbine, then supplemental fuel firing is necessary.

The exhaust gas typically has enough oxygen to sustain stable combustion as the oxygen content of gas turbine exhausts range from about 14% to 16% oxygen by volume (if steam is injected into the gas turbine for NOx control or power augmentation, the oxygen content of the exhaust decreases). In-duct or duct burners can easily be integrated into HRSGs.

The duct burner consists of several burner rows mounted inside a steel frame. Each row comprises a gas distribution pipe with pre-mounted flame stabilizing shields. The duct burner is designed to minimize gas side pressure drop, usually around 0.5” H_2O.

A uniform temperature and flow profile in the duct upstream of the duct burner is crucial to ensure a uniform temperature downstream and emissions within predicted limits. HRSG manufacturers flow model all steam generators incorporating duct burners to try and prevent any problems downstream of the duct burner.

Although duct firing can easily double the steam production of an unfired HRSG, there are also design implications such as:

- Higher cost superheater tube and fin material
- Longer inlet duct to allow complete combustion of the supplemental fuel
- Increased insulation thicknesses on burner duct walls
- Burner management control system to prevent overheating the HRSG
- Addition of a fresh air fan if there is insufficient oxygen in the turbine exhaust to sustain combustion

6.3 Full Firing

A fully fired HRSG is a unit having the same amount of oxygen in its stack gases as an ambient, air fired power boiler. The HRSG is essentially a power boiler with the gas turbine exhaust as its air supply. Steam production can range up to six or seven times the unfired HRSG steam production rate. As the turbine exhaust gas is basically preheated combustion air, the supplementary fired HRSG fuel consumption is less than that required for a power boiler providing the same incremental increase in steam generation. Fuel requirements for the fully fired HRSG will usually be between 7.5% and 8% less than those of an ambient fired boiler providing the same incremental steam capacity. Although fully fired HRSG’s provide large amounts of steam, few applications are found in industry.

6.4 Fresh Air Firing

Fresh air firing refers to the introduction of atmospheric air (fresh air) to support combustion if the gas turbine stops. This addition is suggested in critical steam production applications. Fresh air can be supplied to the HRSG in two ways:

a) Forced Draft (FD) fan

When a significant drop in gas turbine exhaust flow is sensed, an FD fan is started. A double louvered, or guillotine damper with seal air is used to prevent hot gases from going to the fan when it is not in operation and the gas turbine is running. Additionally, a diverter damper prevents air from leaking into the gas turbine ducting when the fan is running and the turbine is off. Switchover time from normal operation to fresh air firing is a concern.

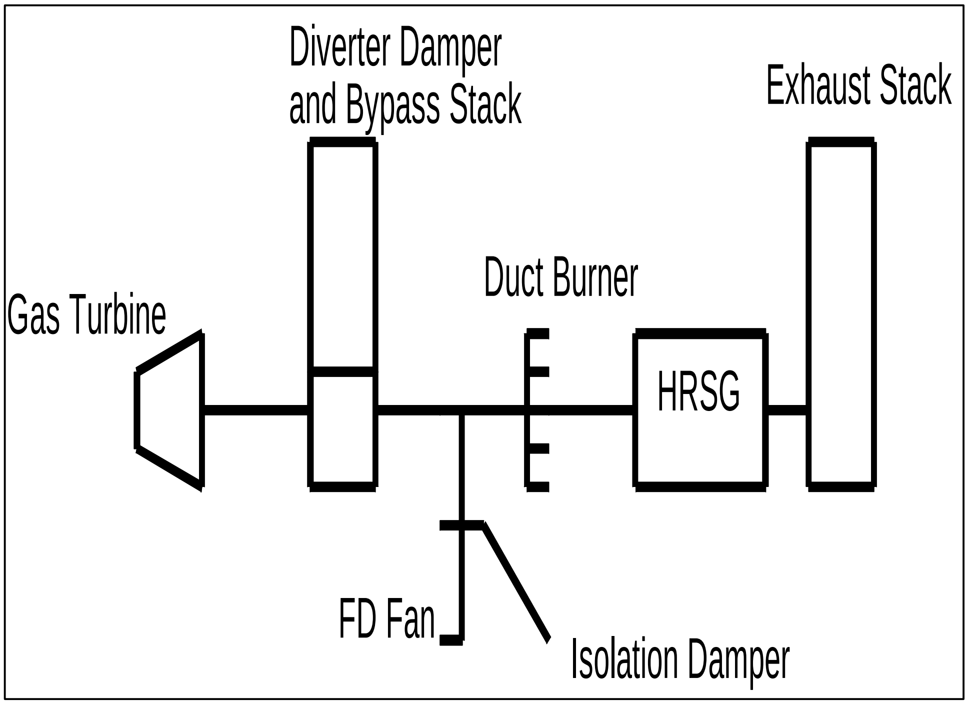


Figure 14 – FD Fan Fresh Air Firing Application

The transition to fresh air firing can be made by either manual or automatic means. Described below are the most common:

Manual:
1) Turbine trip
2) Duct burner trip
3) Gas turbine bypass closes
4) Fresh air firing selected at burner BMS
5) Start FD fan(s)
6) Open fresh air isolation damper. Limit switches on the damper shut off the sealing air fan.
7) Start duct burner

Automatic:
1) Turbine trip
2) Duct burner goes to minimum fire
3) FD fan(s) start
4) FD fan(s) discharge pressure exceeds main duct pressure
5) FD fan(s) isolation dampers open
6) Gas turbine bypass damper closes

7) Fresh air damper sealing air fan shuts down
8) FD fan(s) isolation damper proven open
9) Bypass damper proven open
10) Ensure duct burner element pilots energized
11) Ensure duct burner main elements lit
12) Duct burner released to modulate

While the manual system can take up to five minutes for the duct burner to be released to modulate, the automatic switchover can be completed within approximately 60 seconds from turbine trip. If accurate data is available on the gas turbine spin down and it can be verified that adequate air is provided during the entire transition, systems have been designed that maintain steam pressure (or flow) during the transfer.

b) Induced Draft (ID) fan

It is possible to reduce the switchover time by incorporating an induced draft fan behind the HRSG, which operates continuously. The ID fan reduces the backpressure on the gas turbine during normal operation and must be designed for the complete resistance of the HRSG when the gas turbine is off line. The ID fan always operates at full load and has no time constraints at coming to full load like the FD fan. The disadvantage of the extra power consumption required to drive the ID fan can be compensated with greater gas turbine efficiencies.

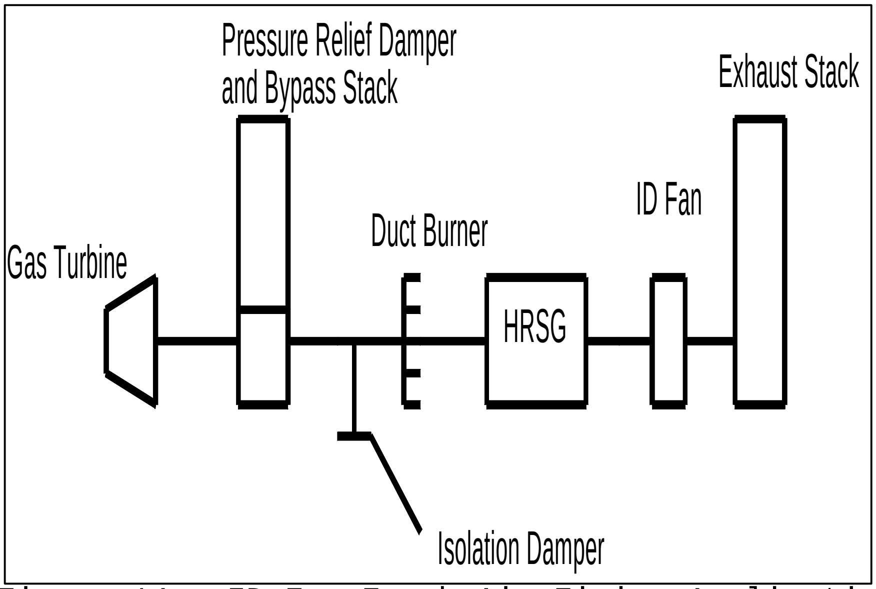


Figure 14 – ID Fan Fresh Air Firing Application

In both cases, the fresh air fan must nearly duplicate the gas turbine flow and temperature characteristic to ensure stable duct burner operation. The burner duty increases significantly when operating on fresh air, as the combustion air must be raised from ambient temperature to the firing temperature.

In most cases the economic evaluation does not favour fresh air firing. It is usually less expensive to put in a small standby package boiler to produce the required steam flow when the gas turbine is out of service.

7.0 Basic Calculations of HRSG Steam Output

Below is a sample calculation for a single pressure HRSG accepting the exhaust from an LM6000 gas turbine. Multiple pressure HRSGs require sophisticated computer programs to calculate steam flows.

Process Data

Gas Mass Flow		990,000 lbs/hr
Gas Inlet Temperature		855 F
Exhaust Composition (% volume)		
	O_2	15.0
	H_2O	7.0
	CO_2	3.0
	N_2	75.0
Steam Pressure		800 psia
Steam Temperature		800 F
Feed Water Temperature		220 F

Assumptions

Pinch Point	25 F
Approach Temperature	20 F
Superheater Pressure Drop	20 psi

Water/Steam Properties

Steam Drum Pressure	800 + 20 = 820 psia
Saturation Temperature	521 F (at 820 psia)
Water Temperature Entering Evaporator	521 – 20 = 501 F
Enthalpy of Steam(800 psia, 800 F)	1399.14 Btu/lb
Feedwater Enthalpy Entering Drum (501 F)	489.06 Btu/lb
Feedwater Enthalpy Entering Unit (220 F)	190.17 Btu/lb

Gas Properties

Gas Temperature Leaving Evaporator	521 + 25 = 546 F
Gas Average Specific Heat	0.27 Btu/lb x F

Superheater and Evaporator Performance

1) Energy transferred

Energy transferred = Gas flow x Gas specific heat x efficiency x (Gas temperature in – Gas temperature out)

Energy transferred = 990,000 x .27 x .98 x (855-546)

Therefore energy transferred = 80,943,786 Btu/hr

2) Energy absorbed by steam

Energy absorbed = Wsteam x (Enthalpy out – Enthalpy in)

Wsteam = 80,943,786 / (1399.14 – 489.06)

Therefore Wsteam = 88941 lb/hr

Calculate Stack Temperature

1) Total energy absorbed by steam and feedwater

Total energy absorbed = Wsteam x (Enthalpy out – Feedwater Enthalpy In)

Total energy absorbed = 88941 x (1399.14-190.17)

Therefore total energy absorbed = 107,527,001 Btu/hr

2) Stack Temperature

Total energy absorbed = Gas Flow x Efficiency x Gas Average Specific Heat x (Gas In – Gas Out)

Gas Out = 855 - (107,527,001 / (990,000 x .98 x .27))

Therefore stack temperature = 444 F

Although this is a relatively straightforward calculation, charts are available specific to gas turbines for obtaining steam flows and stack temperatures of unfired HRSGs.
Please refer to the “Gas Turbine World” Handbooks published each year.

8.0 Other Potential Fluids

8.1 Condensate

Developers of cogeneration facilities usually plan for the thermal host to return some or all condensate to the cogeneration facility. This condensate usually picks up contaminants such as oxygen and iron and must be deaerated and treated prior to being used in the HRSG. Cycle efficiencies can be obtained by preheating this condensate in the HRSG prior to entry into the deaerator and reducing deaeration steam requirements.

Great care must be taken by the designers to ensure the condensate return quality is known. Not paying attention to the actual condensate return composition can cause corrosion problems throughout the plant.

8.2 Makeup Water

Makeup water is added to the steam cycle to make up for any steam or water lost to process, blowdown, venting or draining. This makeup is usually mixed with any condensate return prior to being admitted into the HRSG. As with the condensate return, it is imperative that the makeup water be properly treated prior to entry into the HRSG.

8.3 Glycol

Glycol (Ethylene glycol or propylene glycol) is highly effective heat transfer media for use between –40 F and 250 F. This can be compared to water, which can only be used in applications between 32 F and 212 F. This means that water-based systems won’t freeze up from exposure to normal winter temperatures. In addition, glycol mixtures protect metallic system components from corrosion. As glycol flows through the heat exchanger, it extracts heat from the exhaust gas. The heated glycol can then be pumped to a closed loop system to heat combustion air, natural gas, water or other mediums.

8.4 Ammonia

The “Kalina Cycle” uses a mixture of ammonia and water, in varying concentrations at various stages in the process. The ammonia mixture boils at different temperatures than water and when diluted with water, condenses easily. In the HRSG, the average temperature difference between the gas and ammonia mixture can be kept lower providing for a more efficient design. This cycle has yet to be proven in a large-scale application.

9.0 Basic HRSG Controls

9.1 Drum Level Control

Drum level control is one of the most important control loop existing in a natural circulation and forced circulation HRSG due to the varying loads of gas turbines and duct burners. If the water level is too high, water droplets can be carried over. Low water level can lead to overheating of tubes and failure. The purpose is to regulate the flow of water to a drum to maintain the water level usually near the drum centerline. There are three main types of drum level control:

a) Single element feedwater control

This system is used on small HRSGs that have a relatively large water storage capacity and small demand load changes. The only process variable signal is from a drum level transmitter indicating the level of water in the drum. The output signal from the controller modulates the feedwater control valve to maintain the level at the desired value.

b) Two element feedwater control

When steam demand load changes are more frequent and of a greater magnitude, a two-element system should be used. This system uses drum level and steam flow as variables. The drum level controller detects changes in drum level away from the set point, but because of the shrink and swell effect, the controller output tends to initially give a reverse effect during rapid load changes. By introducing a signal, which represents steam flow into the system, this has the affect of counteracting the effect of shrink and swell and helps to stabilize the drum level during load changes.

c) Three element feedwater control

The most widely used drum level control is three-element control. On a large HRSG with relatively small drum storage capacity, and which are subject to wide and rapid load changes, a three-element feedwater control system should be used.

The three process variables used are steam flow, feedwater flow and drum level. The steam flow signal is summed with the output signal from the drum level transmitter and the resultant output signal acts as the variable set point for the feedwater flow controller.

Regardless of the feedwater control system used, drum level control has proven to be a challenge due to the fluctuating inlet gas flows and temperatures associated with gas turbines and duct burners.

9.2 Burner Management

The burner management system essentially is on/off control, permitting firing at any load when safe conditions exist and automatically stopping fuel input when safe conditions do not exist. Requirements for burner management systems of HRSGs are described in detail in “ NFPA 8506 – Standard on Heat Recovery Steam Generator Systems”.

9.3 Steam Temperature Control

Many processes and utilities require superheated steam at a relatively constant temperature and it is necessary to regulate the temperature leaving the superheater. Different HRSG manufacturers may use various methods of temperature control, but by far the most common method is by spray desuperheaters. As in the case of drum level control, steam temperature can also be controlled by one, two or three element type.

a) Single element control

This system is only used on HRSGs with a single superheater bank where short duration swings in temperature are not critical. The final steam temperature at the superheater outlet is measured and the output from the temperature sensor is compared to the set point. Any deviation between the signal and set point will modulate the spray water control valve.

b) Two-element control

The two-element control uses both the steam temperature upstream and downstream of the desuperheater. This arrangement is used in multiple section superheaters with interstage spray.
The steam temperature controller compares the desuperheater upstream temperature to a set point. Any change in the final temperature away from the set point will cause a change in the desuperheater outlet controller, which also receives a signal from steam temperature downstream of the desuperheater.
As a result, any increase in the steam temperature upstream of the desuperheater will cause a decrease in the set point signal to the desuperheater controller. The output will adjust the spray water flow in order to reduce the desuperheater outlet temperature to the new set point condition.

c) Three-element control

The three-element feedwater control is the same as the two-element control with an extra feedforward signal based on heat input to the HRSG. The feedforward is used to anticipate changes in heat input due to load changes or temperature changes.

9.4 Temperature Control (Once-Through Steam Generator)

Temperature control in a once through steam generator can be achieved without the use of desuperheaters. The point at which the steam-to-water interface exists is free to move through the horizontal tube bank depending on the amount of heat input and the mass flow rate and pressure of the water.
For each gas turbine load, there is a single water flow that will give the required steam outlet temperature at specified operating conditions. The single point of control of the OTSG is the feedwater control valve; the actuation of the valve depends on predefined operating conditions that are set through the Distributed Control System (DCS). The DCS is connected to a feedforward and feedback control loop, which monitors the transients in gas turbine exhaust load and outlet steam conditions, respectively. If a transient in gas turbine, or duct burner load is monitored, the feedforward control sets the feedwater flow to a predicted value based on turbine exhaust temperature and flow, producing steady state superheated conditions.

10.0 Continuous Emissions Monitoring (CEMS) Integration

CEM systems can provide vital information regarding combustion efficiency and pollution levels. Stack gas analyzers measure CO, CO2, SO2, NOx and Unburned Hydrocarbons (UHC). The analyzers can be either extractive or in-situ.

In extractive sampling, the sample is drawn out of the stack, conditioned, and then transported to a remote site for analysis. Conditioning consists of filtration to remove particulates, refrigeration to remove water vapour, heating or insulation of lines to maintain proper temperature and introduction of standard gases for calibration. The measurements are done on a dry basis.

In-situ sampling features an anlayzer mounted on the stack, with its sampling apparatus directly in contact with the stack gas. Measurement of pollutants combines a light source shining across the stack with a receiver/analyzer. It is based on absorption spectroscopy – measuring in the ultraviolet, visible, and near-infrared portions of the spectrum. The molecules of each different contaminant vibrate at specific frequencies, which cancel out equivalent light frequencies in the light beam. Detection of the absorbed frequencies in the spectrum from a narrow band source identifies the pollutants and their concentrations. The measurements are done on a wet basis.

11.0 Emission Control

11.1 Nitrous Oxides (NO_x)

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. Processes have been developed to reduce these emissions in combined cycle power plants. There are various methods to reduce NO_x emissions. Modifications to the gas turbine combustion process can be made by either dry-low NO_x combustion (DLN) or by water/steam injection. DLN refers to a staged combustion process and lean pre-mixed fuel-air mixtures while water/steam injection involves the injection of water or steam into the head end of the combustor. The lowest practical NO_x levels achieved with injection are in the range of 25 ppm for natural gas and 42 ppm for oil. Should additional NO_x reduction be required, equipment can be installed downstream of the gas turbine. NO_x levels as low as 2 ppm are possible.

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 into harmless N_2 and H_2O. See Figure #15 below for a diagram of the NO_x removal process reactions.

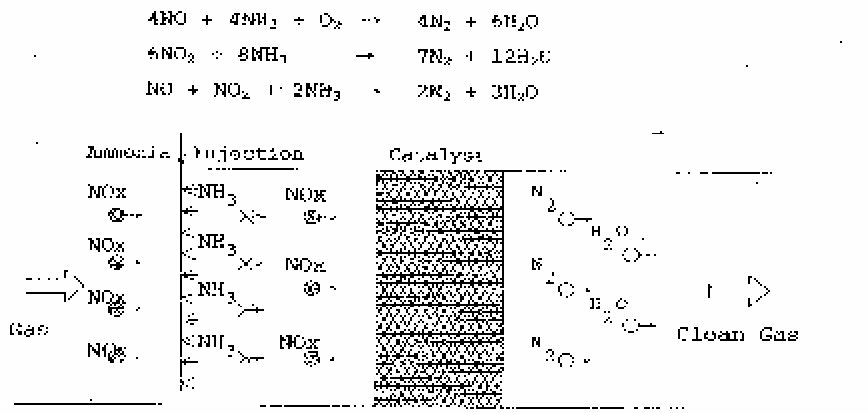
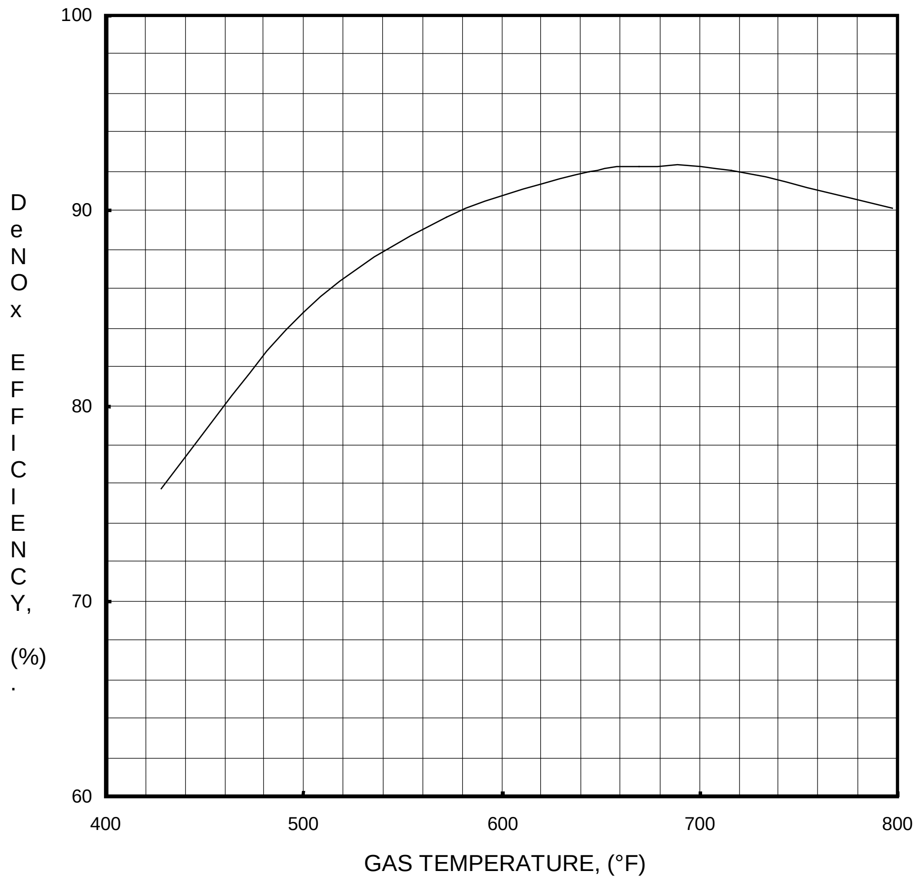


Figure #15 – NO_x Removal Process

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.

The SCR must be located in the appropriate gas temperature zone of the HRSG for maximum efficiency. A typical efficiency vs. gas temperature curve is shown in Figure #16. 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.



Typical DeNOx Efficiency VS. Gas Temperature

Figure #16 – Typical Efficiency Curve

11.2 Carbon Monoxide (CO)

Carbon monoxide (CO) emissions can also be reduced with the insertion of a catalyst in the HRSG. The removal of CO is a much simpler process as only a catalyst is required. Some precious metal catalysts can provide up to 97% reduction of CO by converting the CO to carbon dioxide (CO_2).

CO catalysts can see much higher gas temperatures than NOx catalysts. Gas temperatures as high as 1400 F are possible with a minimum gas temperature of 400 F for acceptable efficiencies.

11.3 Noise

Gas turbine engines are very powerful sources of noise. Sound power levels of 140 dBA to 150 dBA are not uncommon at the exhaust of gas turbine engines. These sound power levels exceed the threshold of pain. In comparison, a normal conversation sound power level is approximately 55 dBA to 65 dBA. Sound power levels in the range of 30 dBA to 40 dBA are usually required by residential areas.

There are two kinds of noise emitted from a gas turbine power plant: high- and mid-frequency noise (a roaring sound, often with a loud whine mixed in) and low-frequency noise (a rumble, constant low hum, or vibration). Mid-frequency noise has a frequency range of 20,000 Hz down to around 20 Hz, and is measured on the "A" decibel scale, which is geared to the hearing range of the average person. Low frequency sounds, those below 20Hz, are barely audible to most people and have to be measured on a special "C" broad-frequency decibel scale.

Low-frequency noise is usually a problem only at simple-cycle gas-turbine powerplants or gas-turbine compression stations where turbine exhaust gas is vented directly to atmosphere through a silencer as HRSG’s effectively diffuse the low frequency noise. If the low-frequency noise is not blocked, it can easily travel for miles. Mid-frequency noise can be reduced with the insertion of duct silencers into HRSG’s. Duct silencers can either be inserted into the inlet duct or exhaust stacks of HRSG’s.