# Steam Turbines and Condensers©

*An introduction to the application of steam turbine generators and condensing systems to cogeneration and combined-cycle power plants. Typical applications included.*

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## COMBINED CYCLE OVERVIEW

The vast majority of today's combined-cycle power plants consist of the following major components, in various configurations:

a) Gas turbine generators (GTG) – producing electricity and offering exhaust gases to …

b) Heat Recovery Steam Generators (HRSG) – producing high pressure steam at one or more pressure level.

c) Single or multi-pressure condensing Steam Turbine Generators (STG) – exhausting to …

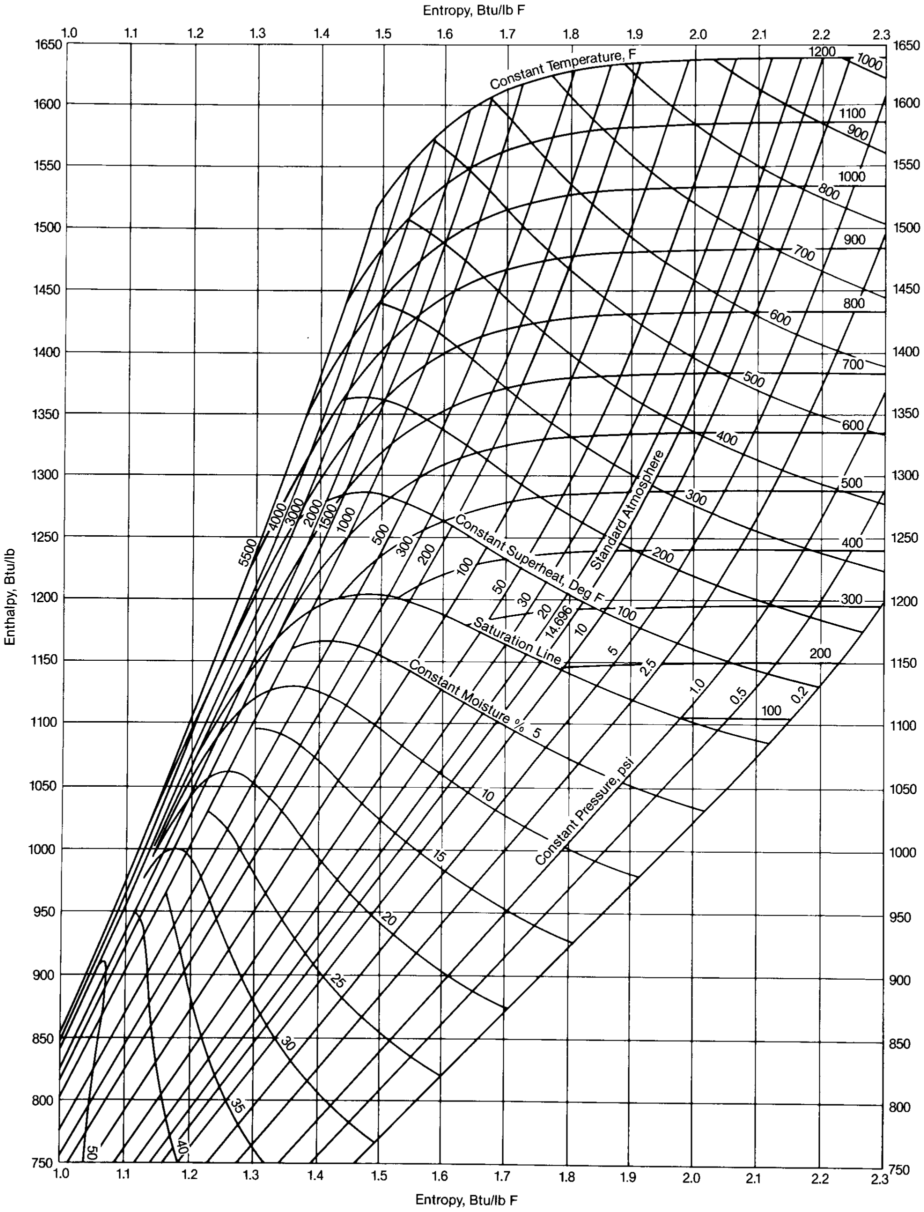
d) Condensing system – to reject heat to atmosphere or water.

This paper covers the application of steam turbine generators and condensing systems in combined-cycle plants.

## BASIC STEAM TURBINE CONCEPTS

### The Basics of Steam

Steam is used in more of today's power generation plants than any other working fluid. Compared to water (whose behavior is predictable due to nearly constant volume), the physical properties of steam are complex. When any one steam property is changed, e.g. pressure, temperature, volume, energy or moisture, all the other properties will also change.



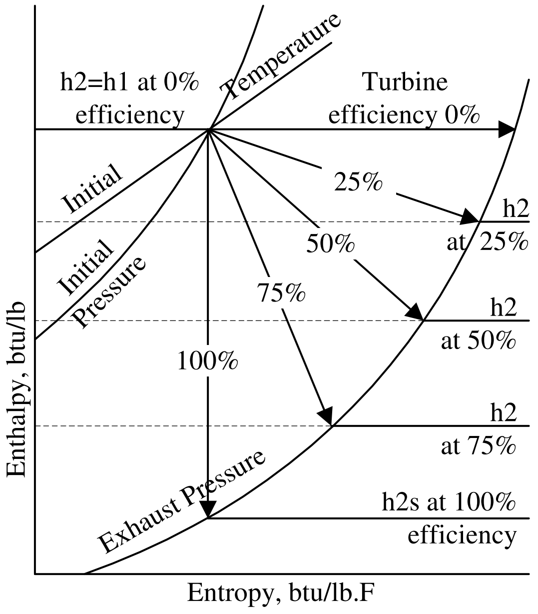
The **Mollier Diagram** has been developed to show this interrelationship of steam properties, and how they all fit together. The vertical axis is **Enthalpy** (given the symbol H), which is usually measured in btu/lb. Enthalpy is a quantification of the usable internal energy which is contained in steam. The horizontal axis is **Entropy** (S), which is the energy in the fluid that is irrecoverable, at a molecular level, and is usually quantified in units of btu/lb.F.

Inside the diagram are shown lines of constant pressure, constant temperature, constant moisture, and the steam saturation line (below which the steam is wet, and above which the steam is dry and superheated).

## Steam Energy Processes and the Mollier Diagram

All real steam energy processes, or "engines" can be plotted on a Mollier Diagram. For example, to extract energy (btu) from a given pound of high pressure and temperature superheated steam at P1, T1 and H1, it is necessary to expand it to a lower pressure P2, which results in a new T2 and H2. The amount of energy released (i.e. the enthalpy drop) from the expansion process is H1 – H2, in btu/lb. In an engine, when 2540 btu are released in one hour, one horsepower (hp) is made for that hour. Similarly, if 3413 btu were released in one hour, one kilowatt (kW) is made for the hour.

If this expansion process could be conducted perfectly and without losses, the steam would expand along a true vertical line, i.e. isentropically. In practical fact, there are always losses associated with the expansion process, and all expansion lines will curve toward the right on a Mollier Diagram. The more efficient the process, the more vertical the line.



It is obvious that the longer the expansion line and thus the greater the difference between H1 and H2, the more energy which will be extracted from the pound of steam. There are several ways to increase the length of the line, including:

a) increasing the initial temperature
b) increasing the initial pressure
c) decreasing the final pressure
d) increasing the expansion process's efficiency.

Thus the push for higher pressure and temperature boilers and HRSGs, for decreased turbine exhaust backpressure and condensing pressures, and for higher efficiency units.

From the Mollier Diagram (and extensive steam tables), we have a good understanding of the thermodynamics of steam, how it can hold energy, how the addition or removal of energy causes changes to it, how the volume, pressure and temperature, density and energy content of it all relate to each other, how to put energy in and take it out with maximum efficiency, and what materials are suited to working with steam.

## Steam Engines and Steam Turbines

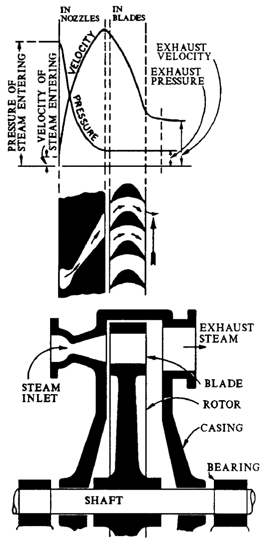
Until the 1880's, steam was expanded in piston engines, e.g. water pumps, stationary engines and locomotives. Where needed, vertical motion was converted to rotary motion via rods, linkages and beams. The practical temperature limit on these steam engines was about 500 deg F, after which point the lube oil used in the cylinders and valve gear cooked and would cause failures.

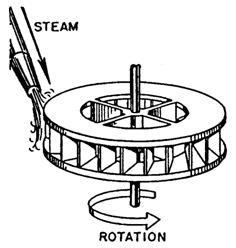
In 1884, Charles Parsons developed the first **practical, modern high-speed steam turbine**, which overcame many restrictions of steam engines.

In the simplest terms, a **steam turbine** consists of a container or casing with steam inlet and outlet connections, enclosing a shaft which holds disk(s), which hold blades or buckets at the periphery. Stationary nozzles, attached to the casing, manage the angle of direction of the steam approaching each rotating blade stage. Because the shaft is supported by bearings outside the casing, and the lubricating oil is no longer in contact with the process, temperatures in excess of 500 deg F are possible.

In the steam turbine, steam is expanded in one of two basic ways:

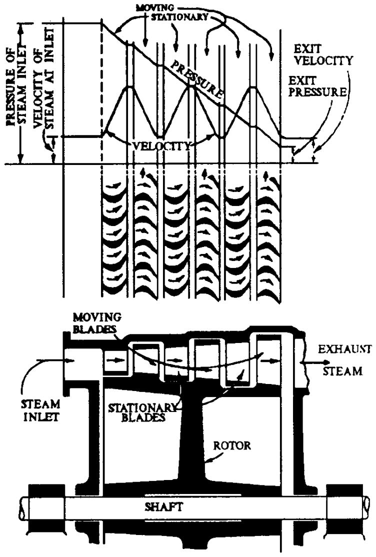
a) Nozzles are used to expand and direct the steam onto the blades, creating a high speed jet at a suitable angle to push them, i.e. **Impulse** design. All the pressure drop occurs across the nozzle, and no drop occurs along the axial length of the rotating blade.

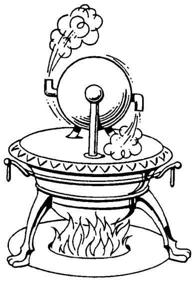




*Branca's Turbine*

b) In the **Reaction** design, pressure drop and expansion occurs across both the rotating and stationary blades, and the blades behave like a high-pressure fire hose, rotating from the reaction that occurs due to the sudden change from high pressure to high velocity steam. In comparison to the impulse design, there is a small efficiency gain, however, maintaining rotating blade tip clearances is critical, or else high pressure steam will bypass the blade length, doing no work.





*Hero's Turbine*

In practice, modern steam turbines combine these two basic blading designs (impulse and reaction) in varying degrees along their blade path, for cost and efficiency reasons.

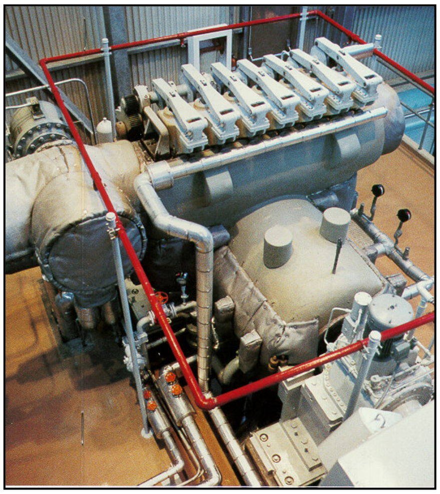
The steam turbine's inlet flow is controlled by a series of valves, raised and lowered as required. Poppet, spool and/or grid valves are also fitted to manage the quantity of steam entering or leaving the various parts of the unit. All valves are managed by digital control systems utilizing speed, pressure and/or load feedback signals to position them.

## STEAM TURBINE EXHAUST CONFIGURATIONS

One of the ways to classifying steam turbines is by the pressure to which they **exhaust** to, which affects the turbine's basic configuration, size, cost and power production.

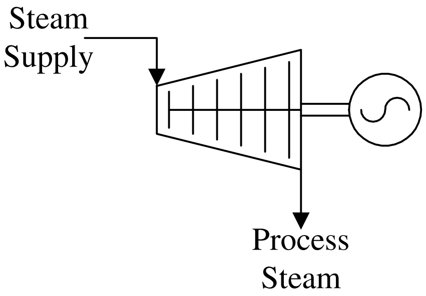
### Backpressure Steam Turbines

**Backpressure steam turbines** generally exhaust to a steam system that is above atmospheric pressure. At these pressures, the volume of steam is relatively small, and consequently the blade path consists of relatively small nozzles, blades, and cylinders, and the exhaust piping is relatively small.



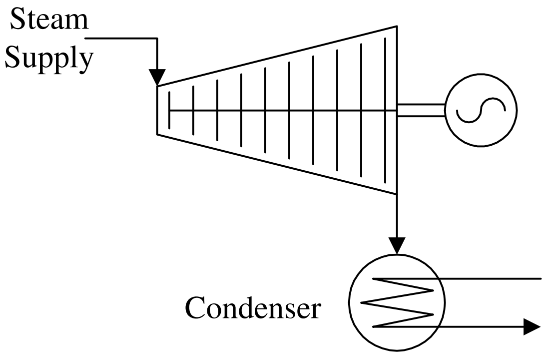
Virtually any inlet-to-exhaust pressure ratio above 2:1 is acceptable (depending upon steam inlet temperature) for a backpressure turbine, although exhaust pressures above 200 psig are rarely used, because of the lack of heat (enthalpy) drop across the machine.

Since all of the exhaust steam flow from a backpressure unit generally goes to a process application, the ultimate capacity of the turbine is only limited by the amount of process steam needed. Having said that, backpressure steam turbines greater than 50 MW are relatively rare, and backpressure units are rarely used in combined-cycle configuration.

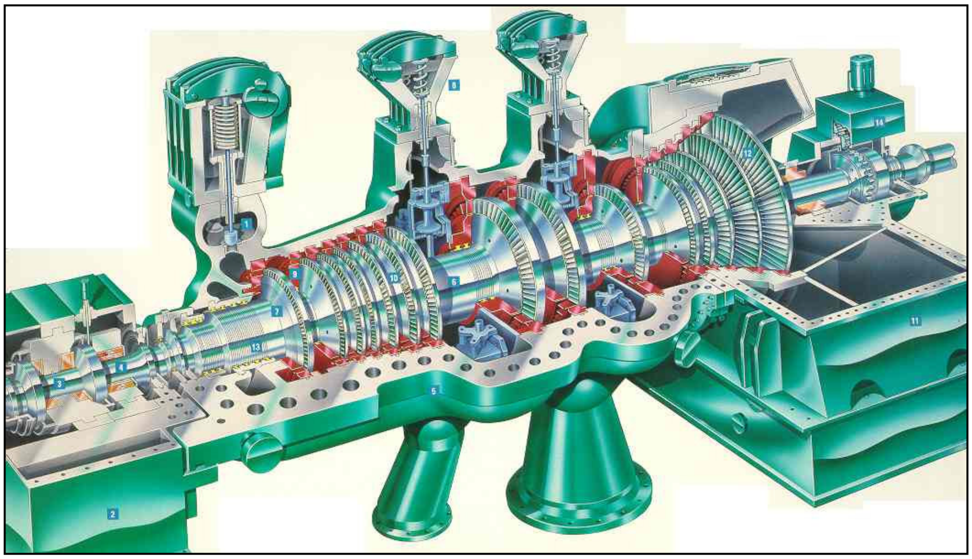


### Condensing Steam Turbines

**Condensing steam turbines** generally exhaust to a system or location significantly below atmospheric pressure, where pressure is measured in inches of mercury absolute, i.e. inch HgA.



At these pressures, the specific volume of steam is very high, and to pass the steam mass flow, much larger blading and nozzle areas are required, and cylinders become very large near the exhaust of the unit. An exhaust hood or diffuser is provided after



the last stage blades, to slow the steam in an orderly manner, to minimize exhaust losses.

The term **condensing** refers to the condensing system that is attached to the unit, which acts to condense (turn back to water, or condensate) the exhaust steam. In the act of condensing, the original volume of the exhaust steam decreases by several orders of magnitude, and since the process takes place in a closed vessel, a steady-state vacuum is created and maintained, which keeps the process / cycle going.

Conventional condensing turbines can be sized from as small as ~5 MW, up to the 1500 MW+ units employed in utility service. For combined-cycle plants, the maximum size tends to be 200~250 MW.

Any inlet pressure up to about 2400 psig is acceptable, while the maximum inlet temperatures are 900~1050 deg F.

Typical condensing pressures are 0.75 inch HgA for the coldest condensing systems, up to a maximum of ~10 inch HgA for air-cooled condensing systems at high ambient temperatures.

## Comparison

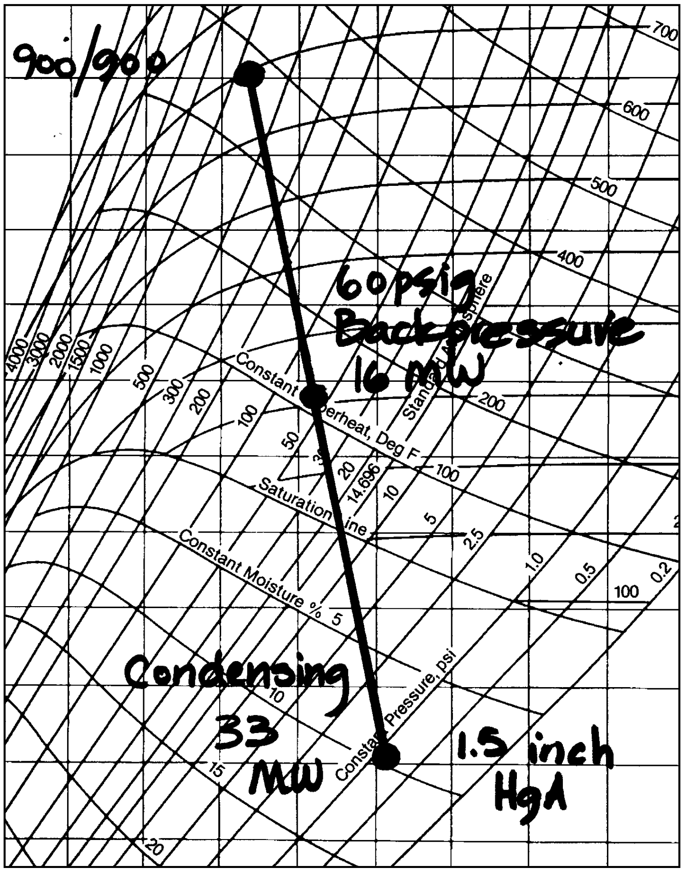
The expansion diagram to the right provides a simple **comparison** of the heat drop and power output for backpressure and condensing steam turbine unit applications.

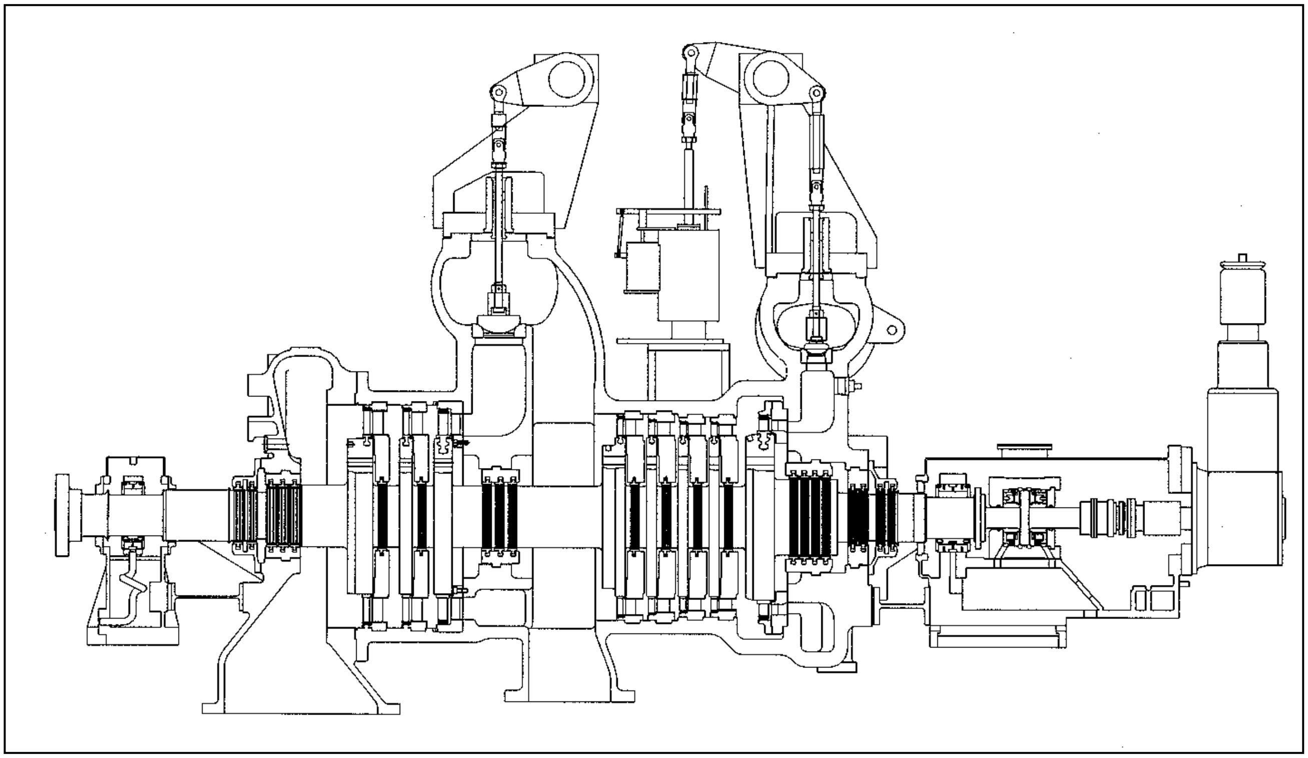
Each turbine receives the same 250,000 lb/hr of 900 psig, 900 deg F steam, and is expanded either to 60 psig in the backpressure unit, or expanded to 1.5 inch HgA in the condensing steam unit.

The **backpressure steam turbine** produces about 16 MW, and provides useful 60 psig process steam at about 405 deg F.

By comparison, the **condensing steam turbine** produces about 33 MW, but no process steam.

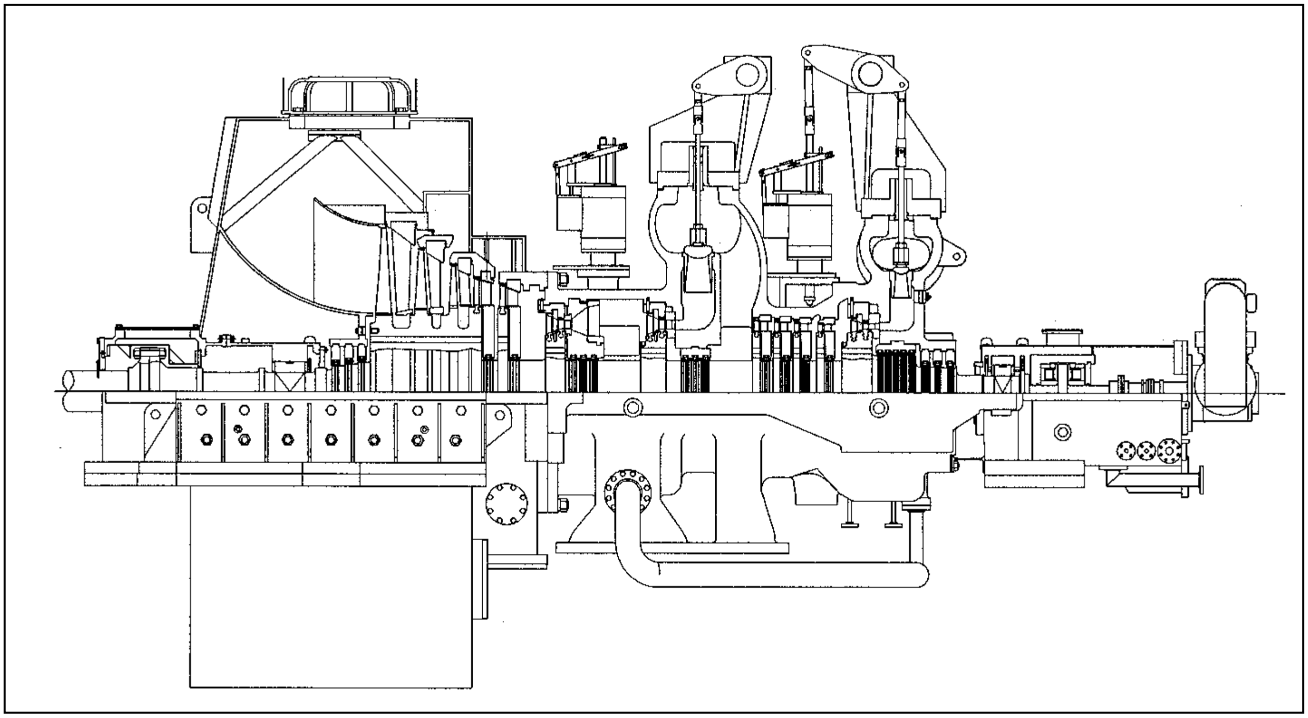
The condensing unit's exhaust results in condensate from the condenser hotwell at about 92 F. In most combined-cycle plants, this is returned directly to the cycle (deaerator). However, with the push for increasing efficiencies, developers are seeking to take advantage of this low-grade, high-volume heat for other useful processes.





*Westinghouse Single Auto-Extraction Backpressure Steam Turbine*

*Westinghouse Double Auto-Extraction Condensing Steam Turbine*

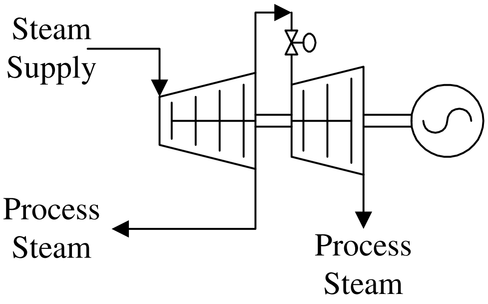


## EXTRACTION, ADMISSION and REHEAT CONSIDERATIONS

### Extraction Steam Turbines

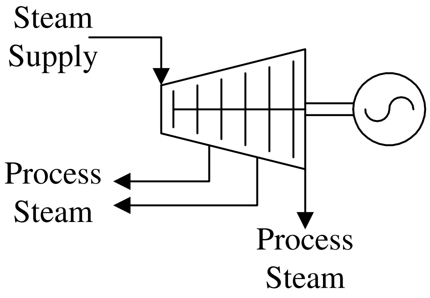
**Extraction steam turbines** provide a tapping point somewhere in the blade path downstream of the inlet valves & inlet control stages, where steam at an intermediate pressure can be obtained. Extractions can be either automatic (controlled), or uncontrolled pressure.

In the **controlled extraction** machines, a series of poppet, spool or grid valves are installed at an intermediate steam chest. The valve position is manipulated by the control system so that some steam is forced out of the steam chest into the extraction piping at the required pressure, while the remainder passes to the lower pressure section of the turbine. This control can be delivered over a wide range of inlet flows, but is expensive because of the additional steam chest.



In **uncontrolled extraction** machines, there are no controlling valves at the tap-off point, and the delivery pressure will be a function of the amount of steam flow downstream of the tap-off point, i.e. higher flows will deliver high tap-off pressures, and vice versa. Uncontrolled extractions can be applied where the downstream process can tolerate pressure variations.

Some specific steam turbine units are fitted with a series of uncontrolled extraction ports, each with a external control valve. As the unit's through-flow changes, the external valves are sequentially opened to deliver steam from the appropriate pressure port, and the unit behaves like a controlled extraction turbine, without the cost of a large steam chest.



Controlled and uncontrolled extraction systems can be applied to both condensing and to backpressure steam turbines. More than one controlled and/or uncontrolled extraction can be provided on a single unit – as seen on the previous image of a GE condensing steam turbine generator.

### Admission Steam Turbines

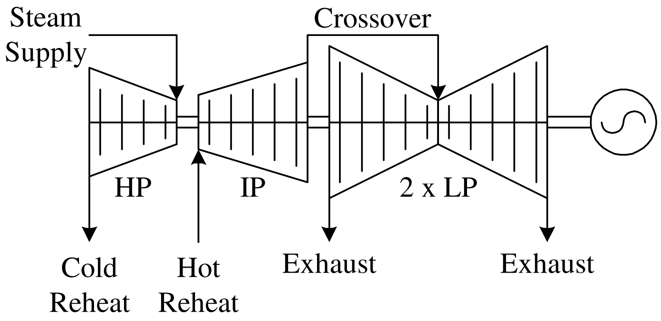
**Admission steam turbines** are similar to extraction units, where a tap-in point is provided in the unit's blade path, downstream of the inlet stages.

Admissions can also be either **controlled** or **uncontrolled** as discussed for extraction units. The only difference is that admission piping systems require a trip & throttle valve, to prevent steam from entering the unit after a turbine trip, which might cause overspeed of the unit.

Controlled and uncontrolled admission systems can also be applied to condensing and backpressure steam turbines. Some units can be configured as admission/extraction, and can thus either accept or deliver steam depending upon extenuating circumstances outside the turbine.

### Reheat Steam Turbines

**Reheat units** are a special condensing turbine configuration applied to large, high pressure power plants, and have been common for large non-nuclear utility units for decades. Reheat is becoming common for the largest combined-cycle plants, where inlet pressures and temperatures are rising to those commonly found in traditional fossil fuel powerplants.



In the reheat turbine, all the steam expanded through the high-pressure section of the turbine is removed from the unit, and taken as cold-reheat to the reheat section of an HRSG.

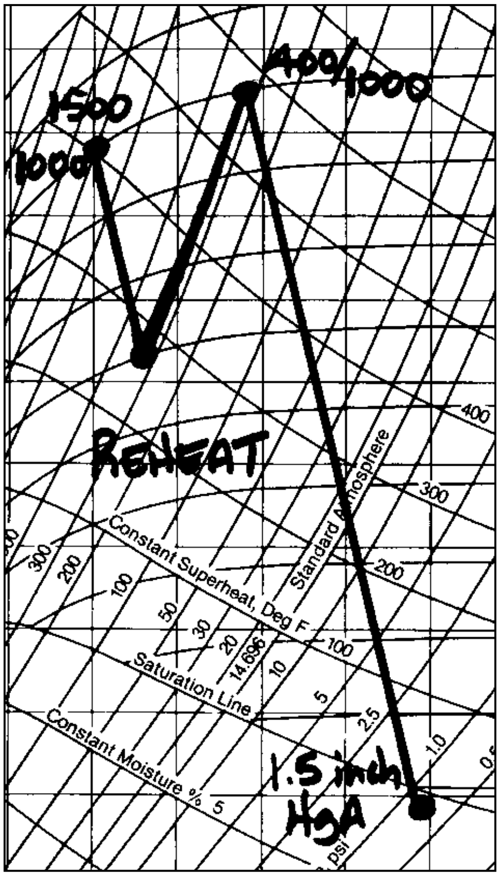
There, it is reheated back to the original inlet steam temperature, and admitted back into the intermediate-pressure section of the steam turbine as hot-reheat, at the same temperature as the inlet although at a lower pressure.

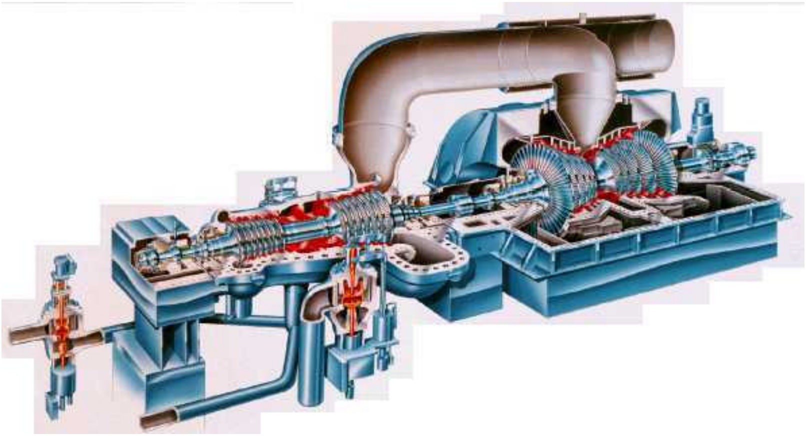
A reheat configuration maintains acceptable levels of wetness in the LP section of the turbine, while the increased length of the steam expansion line results in increased power and efficiency albeit at a significant increase in equipment cost.

Multi-cylinder configurations are best suited for reheat applications, because of the large diameter of the piping takeoffs and inlets, and for thermal considerations.

Additional reheat and intercept valves are required to control the unit during startup and transients.

Inlet/reheat temperatures tend to be 1000~1050 deg F, with initial pressures varying from 1250 ~ 2400 psig, and reheat pressures 400 ~ 600 psig.





GE D11 Reheat Steam Turbine

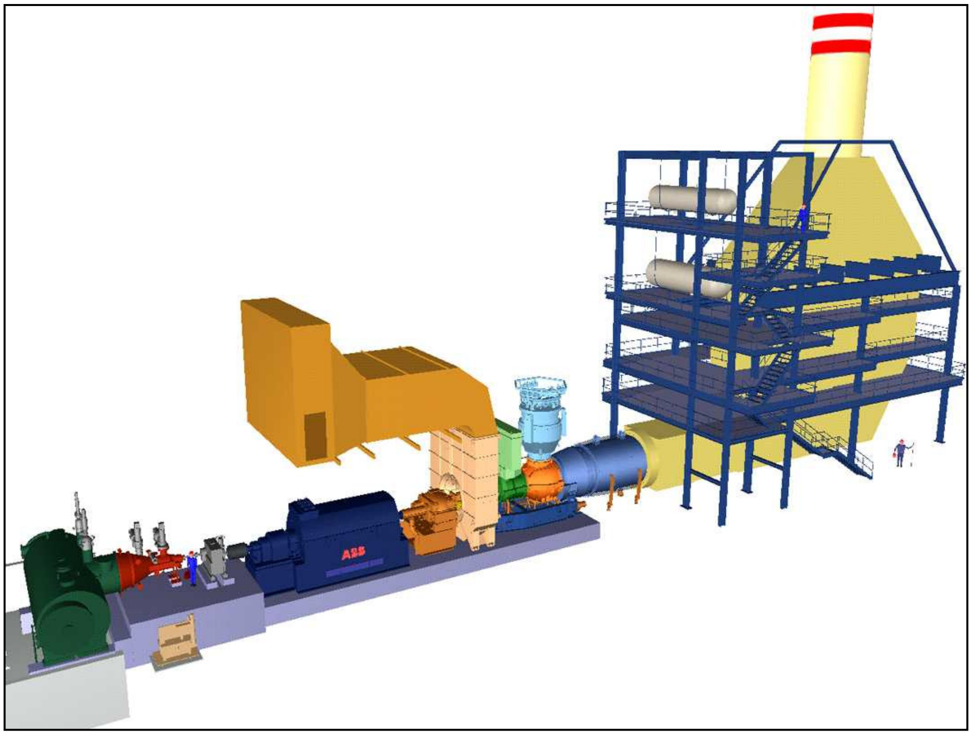
## Combined Gas & Steam Turbine Drivetrain

In an effort to further reduce plant costs, to slightly improve efficiency, and to simplify electrical connections, major manufacturers of large gas turbines and steam turbines offer a combined, common-shaft drivetrain.

The gas turbine is connected to one end of a generator, and a steam turbine to the other end.

A clutch is mounted between the steam turbine and the generator, to allow the gas turbine to commence operation, and the HRSG to commence preparing steam, prior to starting the steam turbine.

The smaller gas turbine manufacturers also offer combined gas & steam turbine drivetrains, employing similar principles.



## TYPES OF CONDENSING SYSTEMS

The actual type of condensing system that can be installed will vary, depending the environmental conditions. Condensing systems can be broken down into the following categories:

- Water-cooled surface condensers and wet condensing systems
- Air-cooled condensers
- Alternative condensing systems

### Water-Cooled Surface Condensers

The most efficient, and thus most popular condensing systems are the water-cooled surface condenser systems – popular in areas where a large amount of cooling water is readily available, and where governing environmental agencies permit their use.

Water-cooled surface condensers can be further categorised by the means in which the heat rejection function is accomplished:

a) **Surface Condensers with Once-Through Cooling Water Systems**, the simplest type and typically the best performance for the least auxiliary power consumption. They are typically applied when the powerplant is located close to an adequately sized river, lake or to the sea, where a pumphouse can be constructed.

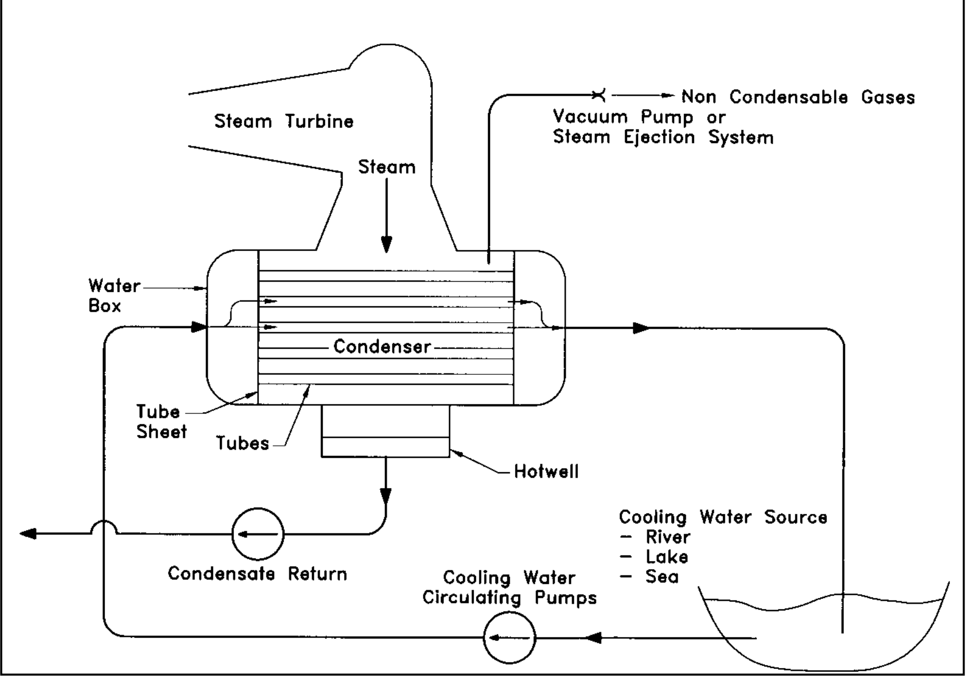
Cooling water is pumped directly from the cooling water source into the condenser inlet water box. The tubesheet connects the waterbox to the tubes, allowing cooling water to pass through the inside of the condenser without contacting the steam-condensate circuit. The outside surface of the tubes makes up the condensing surface and it is this surface area and the cooling water temperature that dictates the condenser performance.

Exhaust steam from the turbine enters the condenser chamber and condenses upon contact with the outside surface of the cold tubes. The latent heat discharged by the condensed steam is transferred through the tube walls into the cooling water. Because the condenser chamber is a fixed volume and sealed from the ambient air, the state-change from saturated-steam to saturated-liquid (i.e. condensate) occurs at a constant pressure and a constant temperature. The large reduction in the fluid specific volume causes the pressure in the chamber to drop to a vacuum condition, to achieve a steady-state equilibrium.

Condensate is collected in the "hotwell" at the bottom of the surface condenser and is then pumped out for reuse in the boiler or HRSG feedwater cycle. The cooling water exits the tubes at an elevated temperature and discharges into the outlet waterbox and eventually returns to the cooling source.

To maintain a vacuum in the condenser, a vacuum pump or steam ejector system is used to remove non-condensibles such as air and other gases that infiltrate the system. The vacuum pump or a large "hogging" ejector is also used to evacuate (de-

Surface Condenser With Once – Through Cooling Water System



pressurize) the condenser at start-up.

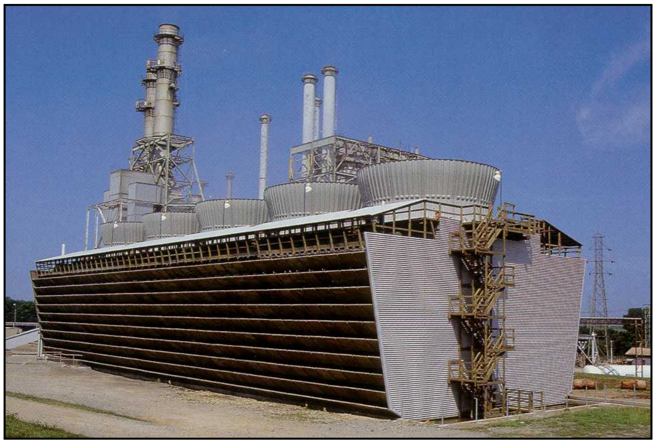
Single-pass and multi-pass surface condensers are both available to suit site requirements. In some cases, multiple inlet/outlet configurations, with divided waterboxes are desired, to allow for flexibility in operation.

While a once-through cooling water cycle is simple and cost effective, it is not always environmentally acceptable to discharge the warm water directly back into the cooling water source. It is quite common for the environmental agencies to restrict the return water temperature discharging back into the original source to 18 deg F rise or less.

b) **Surface Condensers with Evaporative Cooling Towers** eliminate the discharge of hot water back into the original cooling water source, by providing essentially a closed-circuit system for the condenser cooling water. The circulating water is obtained from the basin of an evaporative cooling tower, and after being heated in the condenser circuit, is returned to the cooling tower for cooling.

In general, air is forced or induced through the bottom of the cooling tower, and extracts heat by evaporation from the cooling water stream as it rises and eventually discharges through the top of the tower.

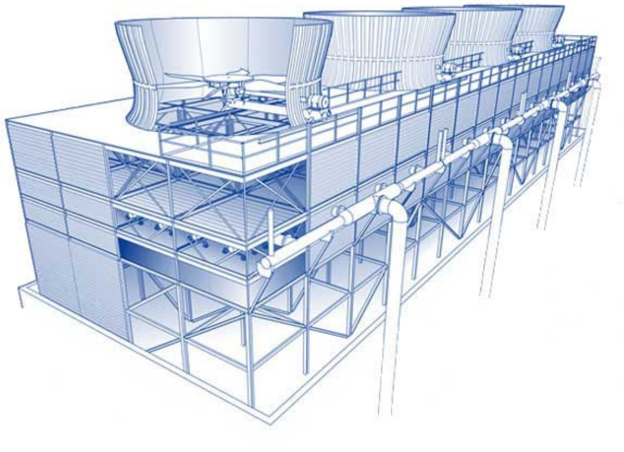
Some circulating water is constantly lost to evaporation, drift and blowdown from a cooling tower, thus an amount of makeup water is still required. In addition, chemical treatment of the circulating water, and the blowdown water is usually required. All cooling towers will generally exhibit a visible plume during operation, unless specific plume abatement measures are taken.



There are two basic types of evaporative cooling towers available:

i) **Natural-draft cooling towers**, with a distinctive hyperbolic shape. Cooling air flow is induced naturally by the hotter (less dense) air in the tower drawing the colder (denser) air from the outside at the bottom.

ii) **Mechanical-draft cooling towers**, that create an airflow through the tower by using either induced-draft (fan at top) or forced-draft fans (located at the air inlet to the tower, susceptible to icing).



## Direct Air-Cooled Condensers

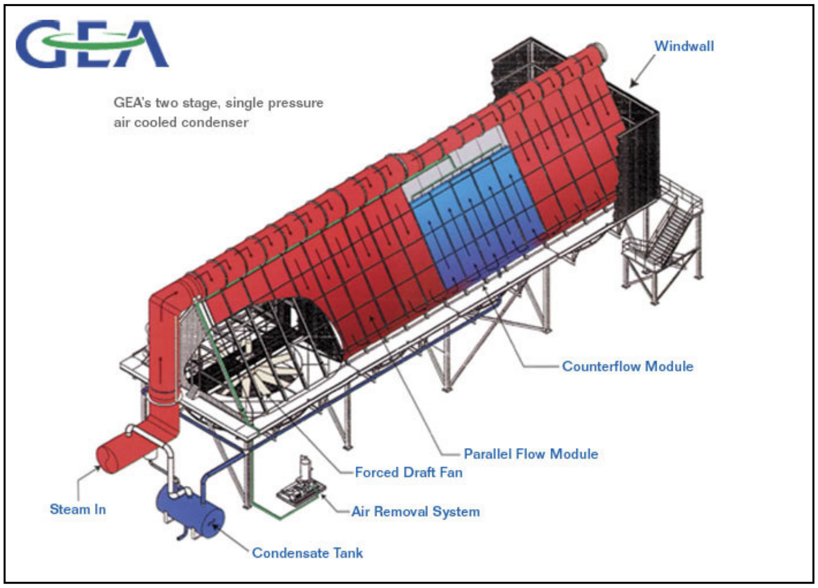
In areas where water is extremely scarce, and powerplants cannot afford even small amounts of cooling water evaporation, sufficient cooling/condensing capacity must be provided without direct air contact with the cooling water circuit. This can be accomplished by using a **dry or direct air-cooled condenser**.

The turbine exhaust steam enters a central plenum/pipe located above a series of finned tubes, sloped down towards a condensate collection piping system, generally in an A-frame configuration. Cooling fans push ambient air across these finned tubes, causing the steam to condense as it progresses toward the hotwell.

Because direct water contact is non-existent in air-cooled condensers, the exhaust / condensing pressure is dependent on the dry bulb temperature of the ambient air.

This means that in very hot weather, the exhaust pressure rises regardless of the relative humidity.

Cold weather operation and icing in the tube bundles are a major concern with direct air-cooled condensers. Variable speed fans and valving systems are employed to reduce heat transfer during potential icing conditions, especially in Canada.



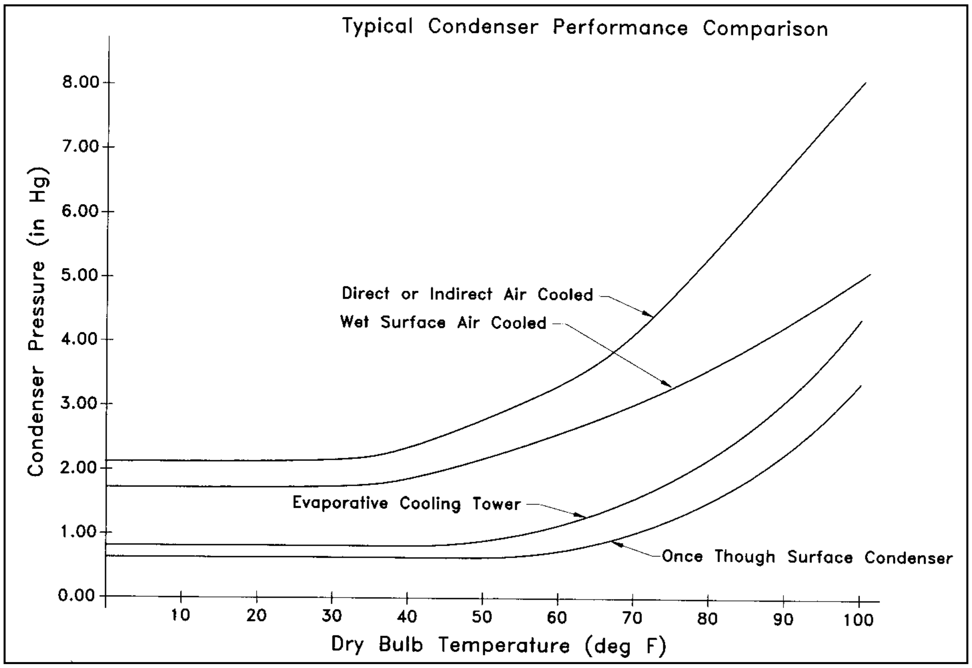
## Alternative Condenser Systems

In addition to the direct-wet and direct-dry condensing systems above, there are several alternate condensing configurations which can be employed, including:

- Parallel or hybrid condensing systems – a combination of a direct air-cooled condenser and a surface condenser and mechanical-draft cooling tower.
- Wet-surface air-cooled condensers.
- Cooling ponds – one to two acres of surface area required, per MW of condensing.

## Condenser Performance Comparison

This figure illustrates the relative performance of the various types of condensing systems available vs. dry bulb temperature, from the once-through surface condensers with river or lake cooling, through surface condensers with evaporative cooling towers, wet-surface air cooled condensers and air-cooled condensers.



## APPLICATION EXAMPLES

### ATCO-OPG
### Brighton Beach
### Windsor, Ontario

580 MW

2 x GE 7FA GTG

2 x AE Energietecknik triple-pressure reheat HRSG

1 x GE D11 STG

River Cooling

### ATCO-EPCOR-Nova Chemicals
### Joffre, Alberta

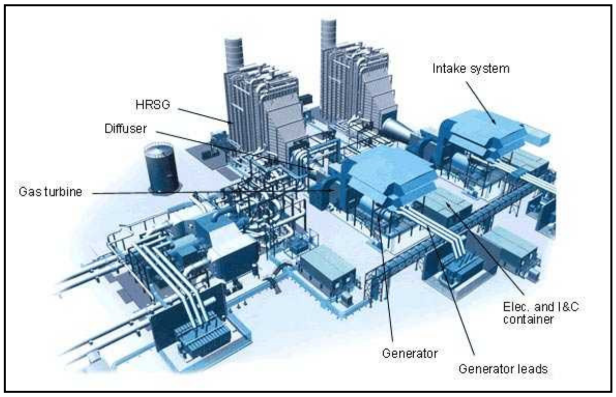
480 MW

2 x Siemens-Westinghouse 501F

2 x Nooter/Erikson triple-pressure reheat HRSG

1 x Toshiba STG

Cooling tower



## APPLICATION EXAMPLES

### Lake Superior Power
### Brascan Power
### Sault Ste. Marie, Ontario

110 MW

2 x GE LM6000PA GTG

2 x Deltak dual-pressure, fired HRSG

1 x GE STG

River / Lake water cooling

### TransCanada Pipelines – Ontario Power Generation

### Portlands Energy Centre
### Toronto, Ontario

***PROPOSED ONLY***

550 MW

2 x GTG

2 x HRSG

1 or 2 x STG

Lake water cooled