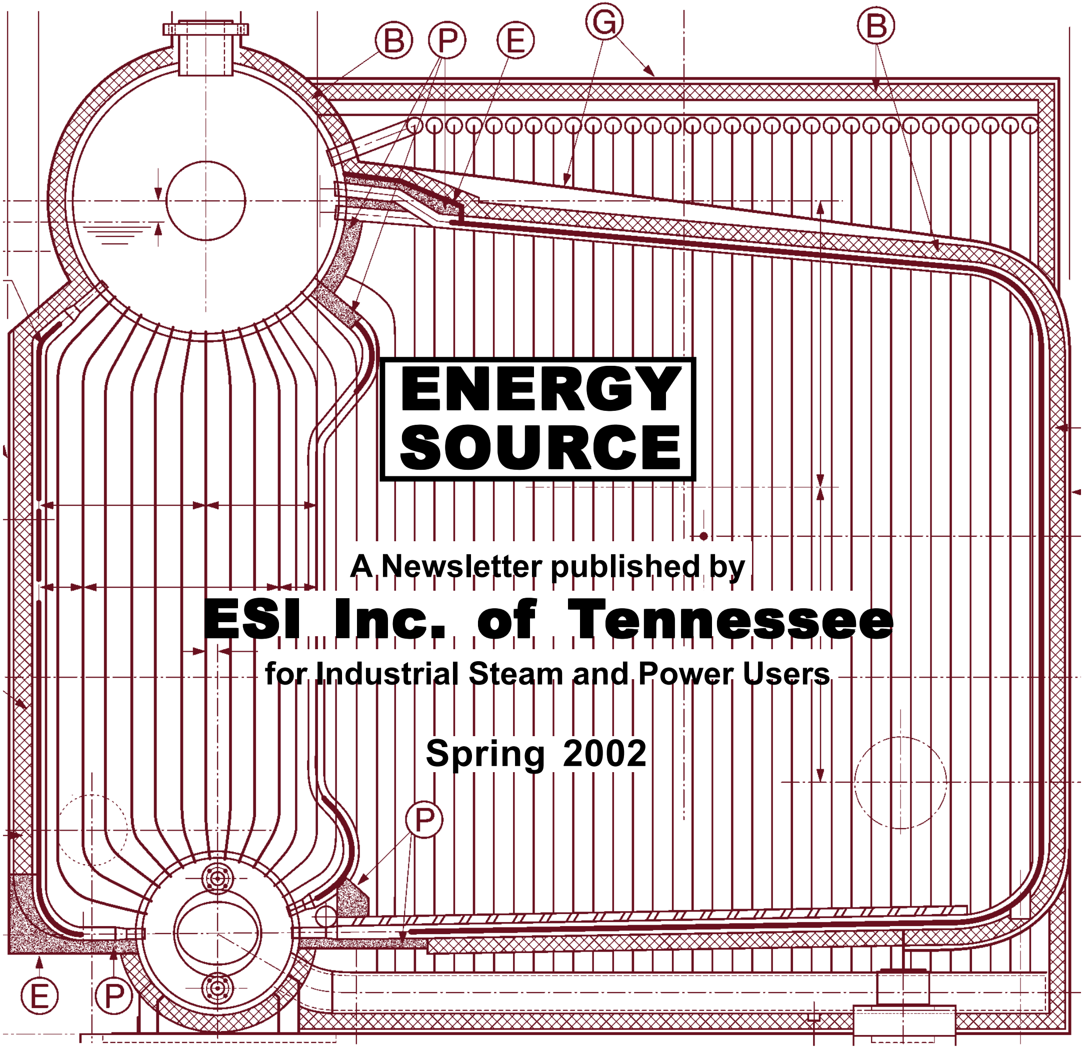


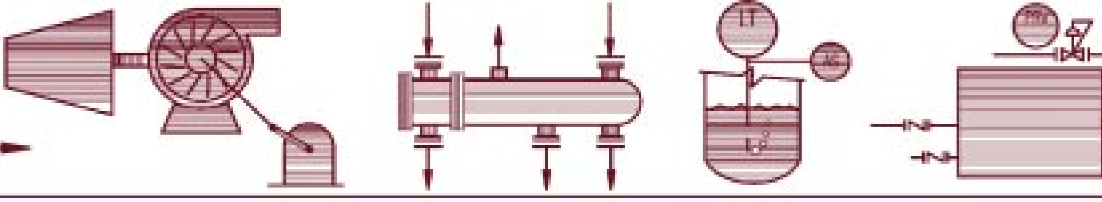
ENERGY SOURCE

A Newsletter published by

ESI Inc. of Tennessee

for Industrial Steam and Power Users

Spring 2002



Cogeneration - Steam Turbine Selection

By: Jeffrey H. White, P.E., Vice President - Sales

Editor's note: The Winter 2002 Issue of the ENERGY SOURCE discussed how to define and optimize the cogeneration cycle. The following article discusses selecting the right equipment for your particular cogeneration application.

One of the key elements in a steam based cogeneration system is the steam turbine. Steam turbines convert the energy in steam to mechanical or electrical energy. Steam turbines range in size from 1 HP mechanical drives to 1300 MW utility stations. With this vast range of sizes, the multitude of options and variations available are difficult to imagine. This article will address some of the more critical aspects of smaller (less than 50 MW) turbine selection.

Operational Requirements

Careful definition of the steam conditions and load ranges for which the unit will be operated are critical in the selection and specification of a turbine. Many turbine manufacturers have multiple models that can be adjusted within ranges to accommodate a given set of steam conditions. The more information the manufacturer is given about the operating conditions, duration at each condition, and all critical factors, the easier it will be for them to provide a turbine selection which satisfies the system's needs while maximizing turbine performance where the biggest gain in overall economics is achieved. For example, a facility may operate at 100% steam load in the winter and 75% in the summer; however, the facility's power load may be at 75% in the winter and 100% in the summer. Considering that the power rate is much higher in the summer than at any other time of the year may drive the vendor to select a machine that maximizes the summer power production, but produces less power in the winter due to a higher extractive load. Definition of the maximum and minimum steam conditions will also allow the proper selection of construction materials for the various operating ranges.

Efficiency

Efficiency in terms of a steam turbine is defined as the ratio of the actual energy produced by the machine divided by the theoretical energy that can be produced by the machine. Steam turbine efficiencies vary from below 55% to above 85% depending on the machine design and cycle configuration. Most people believe the higher the efficiency the better; however, this is not always true. For example, assuming that all of the turbine exhaust energy can be used in the process, the best selection for a back pressure turbine application may not be the machine with the highest efficiency, especially if it has a higher capital cost.

There are two aspects of efficiency that must be considered when evaluating a steam turbine generator. The first is related to the steam turbine's ability to expand the steam and extract the work isentropically. The second aspect of turbine efficiency is related to the auxiliary losses in efficiency from the generator, gear reducer, and other auxiliary components. In reviewing efficiency variations from machine to machine it is important to understand the system's overall mass and energy balance as well as what is driving the economics of the project. Only with these parameters in mind can the proper balance of capital expenditures versus operating benefits be achieved.

Continued on Page 2

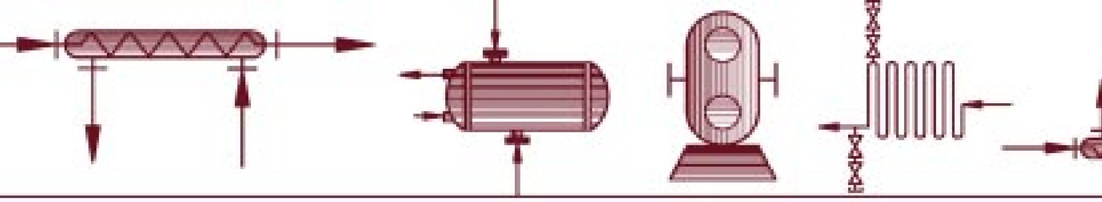
ENERGY SOURCE

The *ENERGY SOURCE* is published quarterly for customers, employees, and friends of ESI Inc. of Tennessee.

ESI is the *SPECIAL FORCES*™ of the Steam and Power Industry providing clients with innovative and cost effective solutions.

Complimentary subscriptions to the *ENERGY SOURCE* are available by calling 770-427-6200 or visiting our web site at www.esitenn.com. If you have any suggestions or comments about the newsletter feel free to call us or e-mail us at energysource@esitenn.com.

Deanna White
Managing Editor



Cogeneration - Steam Turbine Selection... *Continued from Page 1*

Reduction Gears

Another aspect to consider in the selection of a turbine is whether or not the unit should be equipped with a gear reducer. Many manufacturers offer turbine generators with reduction gears for machines up to 40 MW. The installation of a reduction gear offers a great deal of flexibility to the turbine manufacturer because they can design the turbine to run at an optimal speed rather than being limited to the generator speed. This typically results in a smaller and therefore less costly turbine. However, as always there are trade-offs. Gear reducers along with the couplings require additional maintenance and because they are not 100% efficient, they consume a small fraction of the power produced by the machine. Also, gear reducers are just another device in the machine that can fail and shut the unit down.

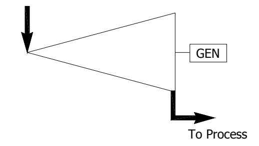


Figure 1. Straight Non-Condensing Steam Turbine Generator

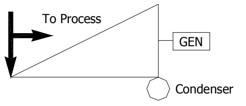


Figure 2. Straight Condensing Steam Turbine Generator

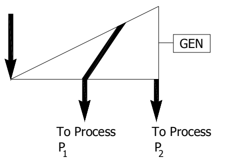


Figure 3. Single Automatic Extraction Non-Condensing Steam Turbine Generator

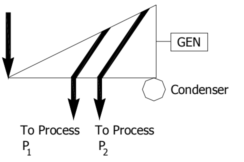


Figure 4. Double Automatic Extraction Condensing Steam Turbine Generator

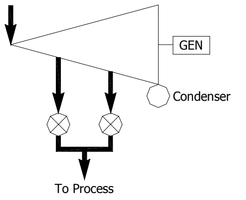


Figure 5. Uncontrolled Extraction Condensing Steam Turbine Generator

Oil Lubrication

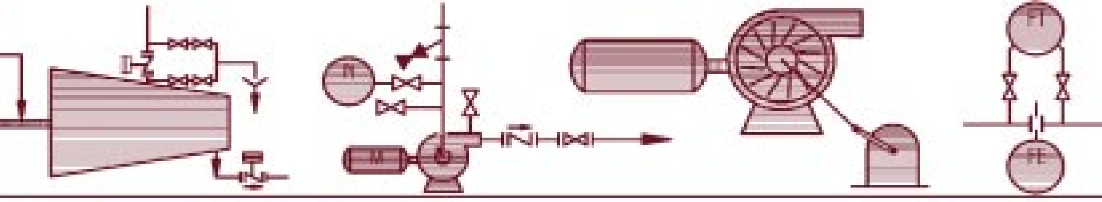
Oil lubrication is also a critical consideration. Turbines today are almost always force lubricated in a recirculation loop. Oil is pumped from a reservoir through the pump to the various turbine components that require lubrication, through a cooler, and then returned to the reservoir. There are several options with oil lubrication systems. Many manufacturers offer the turbine with the oil reservoir "built-in" as part of the turbine base frame. This arrangement saves valuable floor space. Other manufacturers only offer the reservoir as a separate skid, which must be located near the turbine. Oil pumps can be selected in various configurations from direct drive (driven by the turbine itself), to AC drive (driven by an AC motor and located off the skid), to DC drive (driven by a DC motor and located off the skid), to a combination of all of these. The important factor here is to provide adequate redundancy so that a failure of any one pump can be compensated for by a back-up pump. Failure of the lubrication system is certain death for the turbine.

Cooling of the oil is another consideration. The most common method is through a water-to-oil heat exchanger. Typically, water from the system-cooling loop is circulated through the heat exchanger. Care must be taken to prevent contamination of the water through oil leakage; therefore, it is common to install a closed loop cooling water system with an auxiliary water-to-water heat exchanger. In instances where water is not available for cooling, an oil-to-forced air cooling system can be utilized. Additionally, a decision must be made as to whether an oil purifier should be installed. The purifier will remove any contaminates in the oil and extend the life of the oil and lubricated parts.

Controls

Another critical area that should be considered is turbine control and protection. Most turbine manufacturers utilize PLC based control systems for control, monitoring, and safety shutdowns of the unit. These systems are usually fully functioning systems with the capability of communicating with the plant control systems through a variety of methods. The key requirement in specifying this equipment is to determine how the unit

Continued on Page 4



Ask An Engineer!

In the April 2001 issue of "Plant Engineering" magazine, ESI had an article titled "Maintaining Boiler Safety." Rob Gilman of Akzo-Nobel in Houston, Texas contacted ESI via our website requesting the answers to a few questions related to that article. Rob indicated that he was in the midst of evaluating his current quarterly and annual preventative maintenance programs. Following are his questions and our responses.

Question #1

"Based on present industry practices and guidelines, what routine preventative maintenance checks are performed on a steam boiler and how frequent?"

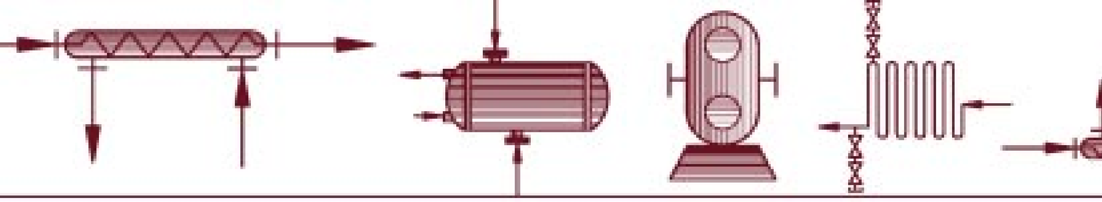
Steam boiler systems have a variety of tests and checks that should be conducted at various time intervals to ensure the continued operating safety of the system. These checks and inspections are generally mandated by state boiler codes and your insurance carrier while others are simply good industry practice. The routine checks and inspections that should or must be conducted on a steam boiler system are as follows: boiler water chemistry checks, fireside and waterside inspection, safety relief valve check and recalibration, combustion control check and recalibration, low water alarm and cutout interlock checks, burner management system safety interlock checks, and visual inspection of control valve and damper instrument air tubing.

Boiler Water Chemistry Checks- The boiler and feedwater chemistry of an operating steam boiler should be checked and recorded daily. The procedures for these simple water chemistry tests are usually developed by the company and service technician providing water treatment chemicals to your facility. The service technician can instruct your boiler operating personnel on how to conduct these tests and the data to be recorded. This daily testing and monitoring will give you timely feedback when the water treatment or blowdown systems are not functioning properly. Many people underestimate how quickly waterside deposits can be accumulated in a boiler operating with hardness in the feedwater. As you can imagine, it will not take long before scale deposits can cause furnace tube failures due to lack of heat removal resulting in tube overheat.

Fireside and Waterside Inspection- Most states and steam boiler insurance carriers require a fireside and internal waterside inspection at least once a year. This inspection will identify any potential waterside deposits and tube erosion and corrosion problems that may exist. Even with acceptable daily testing and recording of feedwater and boiler water chemistry, waterside deposits can still be experienced over the course of a year's operation. Waterside deposits indicate either failure of the water treatment system equipment to operate properly or problems with the water chemistry program in general.

Safety Relief Valve Check and Recalibration- Some state boiler codes and many boiler insurance companies require the annual inspection, testing, and recalibration of boiler, deaerator, and steam system safety relief valves. ESI believes this to be a good and generally accepted preventative maintenance practice to be performed during the annual boiler outage for inspection and miscellaneous repairs. ESI does not recommend the periodic checking of safety relief valves by lifting the relief valve levers or increasing the operating pressure to lift safety relief valves. Anytime a safety relief valve is lifted and has to reseat under actual operating conditions, there is a risk of creating a minor steam leak that over time cuts the seating surface causing a major leak and safety relief valve problem. Many facilities utilize their safety relief valves to control the high end of steam header pressure allowing these valves to lift periodically and quite often. Safety relief valves were not designed for these operating conditions, which could cause safety relief valve functional problems and even possible failure requiring a forced outage.

Combustion Control Check and Recalibration- Most facilities do not check combustion control calibration until a noticeable problem exists. Although ESI knows of no code standard requiring such, we recommend that the combustion controls of a steam boiler be checked and recalibrated at least annually. This preventative maintenance will not only potentially identify current or impending future problems with devices such as control valves, damper actuators, transmitters, and other flow measuring devices, but the cost of this activity is usually money well spent due to combustion efficiency gains that are realized by keeping combustion



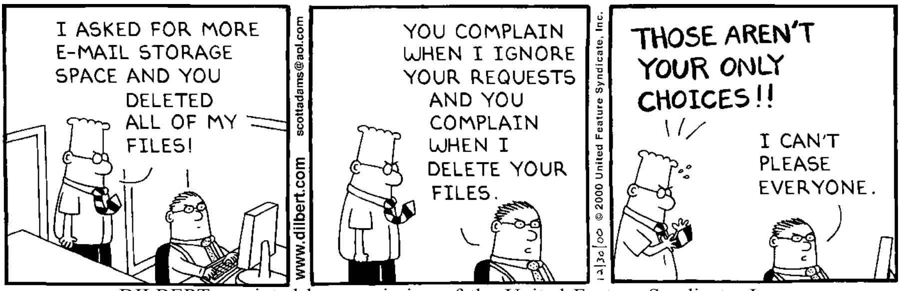
Cogeneration - Steam Turbine Selection... *Continued from Page 2*

will be operated. What will be the operating philosophy? Do you need local control or control from a central control room on the other side of the plant? The control system typically monitors critical components to insure proper operation including: speed control, safety trips in case of overspeed or lube oil system failure, lube oil system control, bearing vibration, generator controls, and various component temperature controls.

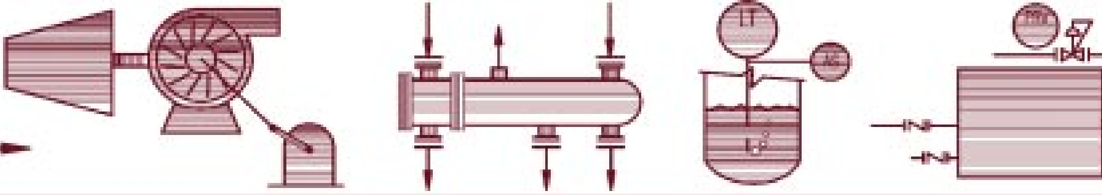
In addition to the above control features, a decision must be made surrounding how the unit exhaust or extraction points will be controlled. For example, if the cycle design is built around a low-pressure extraction for deaerator steam supply, there are three possible scenarios for control of this extraction. First, the extraction could be completely uncontrolled. Under this arrangement, the deaerator pressure would be allowed to vary across the load range of the turbine. This is the least costly alternative for an extraction; however, on a condensing turbine system if the turbine exhaust flow rate was high, the extraction pressure would decrease and vice versa in the case of a low flow rate. This variability might be acceptable in a deaerator loop; however, it would probably not be tolerable in a process steam loop. If uncontrolled extraction of steam is not acceptable, the next possibility for extraction control would be what is referred to as off the machine control. With this system, an uncontrolled extraction would be installed on the machine and a back pressure control valve would be installed to maintain header pressure. The control of this valve can be integrated into the turbine vendor’s control system or in the main plant control system. This type of approach is next in line on the cost curve; however, it is limited in the ability to control over wide operating ranges and has a negative impact on turbine efficiency as compared to on board control. On board control is the third method of control for turbine extraction. With this arrangement, a set of valves is installed in the machine and regulated by a series of linkages. This type of control system provides the tightest extraction control and provides the most efficient operation of the machine over the widest load range; however it also has the highest initial cost.

Conclusion

Obviously, we have only scratched the surface in this article when it comes to the specification and selection of a steam turbine generator system. There are many other equally critical decisions that must be made to properly select a steam turbine. Other questions that should be answered include: “ Should a turning gear be provided?”, “What about system noise?”, “ How do you specify a generator?”, “What should be included for generator controls?”, “What method will be used to cool the generator?”, “Should a crane be included for maintenance?”, “What turbine arrangement is best for the application?”, along with countless others. The key in selecting this and any other piece of power plant equipment is to understand the process and all the critical factors in the process. If you have any questions concerning this article or have a possible steam turbine application, please call the *SPECIAL FORCES*™ of the Steam and Power Industry today at 770-427-6200 or e-mail us at info@esitenn.com. Look for the next issue, *ENERGY SOURCE* Summer 2002, where we will continue this cogeneration series.



DILBERT reprinted by permission of the United Feature Syndicate, Inc.



Ask An Engineer! continued...

controls in calibration. ESI also recommends that continuous combustion monitoring equipment such as an oxygen analyzer be installed in each boiler.

Low Water Alarm and Cutout Interlock Checks- Except for a fireside or waterside explosion, nothing can cause greater damage quicker than continuing to fire a boiler with a low water condition. In spite of the state of the technology, many boilers are destroyed annually due to low water incidents. ESI has always been a strong proponent of ensuring all boilers are equipped with low water alarms and trips, even before they became code mandatory on solid fuel fired boilers. ESI has always designed our low water alarm and cutout circuits with redundant parallel-wired pushbuttons to facilitate the blowdown of the water column and gauge glass assembly while the boiler is operating. This blowdown operation allows the functional operation of these devices to be checked on every shift or at least once a day without tripping the unit. This will ensure that your boiler is always protected and that your gauge glass, water column, and low water devices are kept clean and functional. ESI is so adamant regarding the importance of this item that we generally include redundant drum level transmitters, low water cut-out devices, and reflex type illuminated gauge glass assemblies on each boiler installation.

Burner Management System Safety Interlock Checks- The low water cutout is a burner management system safety interlock that should be checked every day. The other burner management safety interlocks only require check and verification of operability on an annual basis. These can be checked either during an outage using a voltmeter or when the boiler combustion controls are recalibrated by bringing the boiler down to a minimum load to minimize plant steam system upsets while systematically checking that every device will trip the boiler. Devices requiring initial calibration (i.e., pressure switches, etc.) should be recalibrated annually as well.

Visual Inspection of Instrument Air Tubing- This may sound like an unusual preventative maintenance inspection item; however, this is one that should be done annually and takes very little time. Boiler system components often have some minor vibration resulting from burner and fan operations. ESI has recorded instances where instrument air tubing has been in contact with a pronounced edge of a windbox, duct, breeching, stiffener, etc. Over time, this point of contact and the minor vibration has worn a hole in the tubing. When this happens, the damper or valve can close when the control system actually thinks it is open. This situation can be very dangerous, especially in parallel positioning control systems and other combustion control systems that are not cross limited flow tieback in design.

Question #2
"What preventative maintenance or reliability checks are performed off line, on by-pass, or during normal operation?"

Description of Check or Test	Normal Operation	By-Pass Operation	Outage
Boiler water chemistry checks	X		
Fireside and waterside inspection			X
Safety relief valve check and recalibration			X
Combustion control check and recalibration	X		
Low water alarm and cutout interlock checks		X	X
Burner management system safety interlock checks	X		X
Visual inspection of instrument air tubing	X		X

Question #3
"Are there any liability or insurance concerns regarding checking switches on by-pass and if so, are there any states with restrictions?"

ESI is not aware of any state boiler codes that prohibit checking safety devices on by-pass. Insurance companies encourage the testing of safety devices as long as the test procedures do not create a dangerous situation. A properly designed by-pass system for low water alarm and cutout testing requires that the operator manually engage and hold the spring loaded and normally open by-pass pushbuttons during testing. ESI uses two buttons in series so if one button fails closed, the low water cutout system protection is still functional. This design prohibits the operator from inadvertently leaving the safety interlocks disengaged once the testing is completed.

ESI is the *SPECIAL FORCES*™ of the Steam and Power Industry providing clients with innovative and cost effective solutions. If you have a technical question about your steam or power facility - **Ask An Engineer!** Call Deanna White at 770-427-6200 or e-mail us at info@esitenn.com.