

STEAM TURBINE GOVERNING SYSTEMS AND ELECTRONIC GOVERNOR RETROFIT

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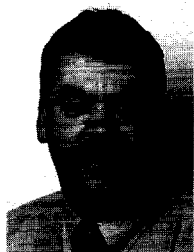
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steam turbine applications. These would include initial cost, future maintenance costs, reliability, availability of remote control, computer interface, and turbine performance. Many benefits may be realized by choosing the proper steam turbine governing system, whether it is a mechanical type governor, an electrical analog or digital governor, or a programmable logic controller (PLC) system. In order to utilize the equipment in a safe, reliable, and effective manner, coordination among the customer, prime mover manufacturer, and control supplier is crucial. The user must write the complete specification stating their exact requirements. The prime mover manufacturer will amend the specification around the correct system to meet the customer's prerequisites and the turbine application. The control manufacturer will then refine the specification to produce the correct components to meet the operational requirements. The selection of the correct and most reliable governing system for a steam turbine is a very significant one, and many areas should be considered prior to making a final decision. The authors cover the critical topics listed above by discussing a number of issues. A short discussion is given on speed/load and process control possibilities, indicating what governor control will best suit a particular steam turbine application. The tutorial concentrates on the appropriate complete control system, including overspeed protection systems that will be required to operate a steam turbine in a safe and reliable manner. Safety and reliability are achieved by the selection of the correct system components such as actuators and feedback systems and their correct placement in the control scheme. Also covered is the importance of selecting a single, redundant, or a fault tolerant type digital control system and the option of a PLC control system.

Finally, when converting from a mechanical control system on a steam turbine to an electrical control system, it is of paramount importance that all aspects of the retrofit are considered in the early stages of the project. Many of these issues are covered with tables and charts in the latter portion of this paper. It is up to the reader to apply this coordination information in all phases of the retrofit process. Also provided are a number of sections on the theory of operations and application guidelines for steam turbines.

ABSTRACT

Steam turbine retrofitted governing systems are being designed with today's technology to operate a turbine in a safe and reliable manner. The design is completed with an extreme amount of effort being concentrated in the system operation and system interface areas. There are numerous control and supervisory equipment manufacturers who are capable of producing a system, which may be utilized to operate over the complete line of steam turbine applications. Many areas must be investigated prior to placing an order, installing the system, and operating the retrofitted governing equipment. This paper will aid the end user in this investigation.

INTRODUCTION

Numerous users have taken advantage of state-of-the-art technology in steam turbine controls in the past few years. There are many considerations to be taken when choosing a governor for

FUNDAMENTALS OF SPEED AND PROCESS CONTROL

Droop is defined as a decrease in speed or frequency with an increase in load (Figure 1). Droop is expressed as the percent that the speed drops below no load speed when the turbine is fully loaded. Droop control can also be referred to as "proportional only" control. On a steam turbine, a droop (proportional) only governor produces a change in valve position proportional to the signal between the speed set point and the actual speed. There is a fixed linear relationship between the turbine speed and the position of the turbine governor valve or valve rack. The main disadvantage of droop only control is that it cannot completely eliminate the error caused by a change in load. In other words, any change in turbine load will result in a corresponding change in turbine speed.

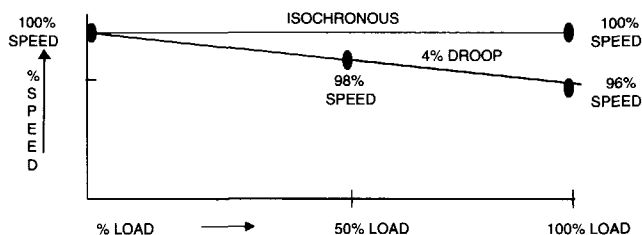


Figure 1. Droop Curve.

Isochronous control means repeating at a single rate or having a fixed frequency. In other words, no decrease in speed with an increase in load. This is accomplished with integral combined with proportional (PI) control to provide an automatic reset action that eliminates the offset of the droop only governor. To minimize the over and undershoot of the controller, derivative (D) control is used in conjunction with proportional and integral control. Derivative control changes the output of the governor proportionally to the rate of change of the error signal. Hence, most electronic governors that provide steam turbine controllers are PID controllers.

For example, a turbine generator set operating in the isochronous mode will operate at the same speed/frequency regardless of the load. An isochronous electronic governor compares the actual speed with the desired set point. If there is a difference between the actual speed and desired speed, the governor sends a signal to the actuator operating the steam valve, which will adjust the speed until the two are again balanced. This operating mode would be used by a turbine generator set running alone on an isolated system (Figure 2).

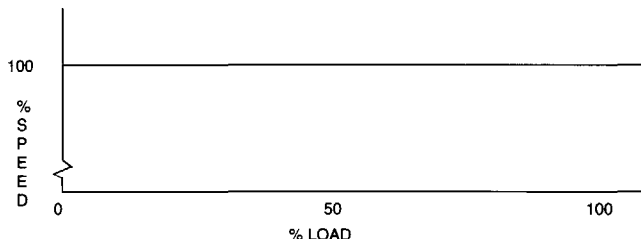


Figure 2. An Isochronous Governor Maintains Constant Speed at All Loads to 100 Percent.

When a turbine generator set is connected to the utility grid, the speed cannot be changed, but the speed set point can. When the speed reference is raised, the valve will open, increasing the load. If the reference is lowered, the valve will close and lower the load. In this case, the droop governor becomes useful as a load controller. Although a poor speed controller, the droop governor becomes an excellent means of load control when the generator is synchronized to the grid. Hence the term, speed/load control.

Suppose a synchronous generator with a mechanical droop governor is connected to the utility grid and an operator is asked to control the inlet pressure. How could this be done? The operator would read the inlet pressure on a gauge and raise the speed reference as required to maintain the inlet pressure. In a sense, one controller, the operator, is controlling or cascading another, the governor. Therefore, cascade control is a control scheme where one controller tells another controller what to do. The task could be done in a more practical and economical manner than the example above by using a process controller whose output feeds into the remote speed reference of an electronic governor. In this case the process controller will "cascade" the speed controller. An even better solution would be to use a governor with a second PID reference that can cascade the speed reference.

PROCESS APPLICATIONS

A straight noncondensing turbine is the economic choice when all exhaust steam can be used for heating or other uses. An example

of this type of system is when high-pressure steam is available to supply a topping unit, and in turn this turbine's exhaust steam is utilized to provide flow to lower pressure prime movers. A noncondensing turbine can be applied to increase power output with the same fuel consumption (Figure 3).

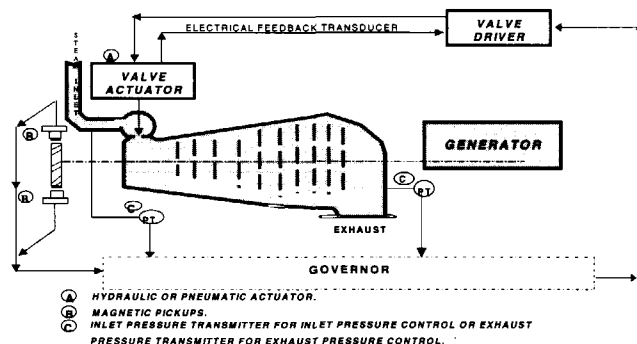


Figure 3. Multivalve Noncondensing Steam Turbine.

A straight condensing turbine is used when power is the only concern and it must be produced on a minimum amount of steam. To improve the plant's efficiency, these units can be provided with multiple uncontrolled extraction openings for feedwater heating (Figure 4).

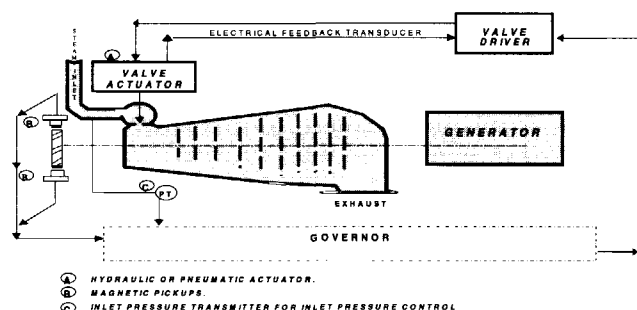


Figure 4. Multivalve Condensing Steam Turbine.

A condensing mixed pressure turbine automatically uses as much low-pressure induction steam as available, supplementing it with as much high-pressure steam as required to carry the load. This type is used when more power must be produced than is possible with the available low-pressure steam (Figure 5).

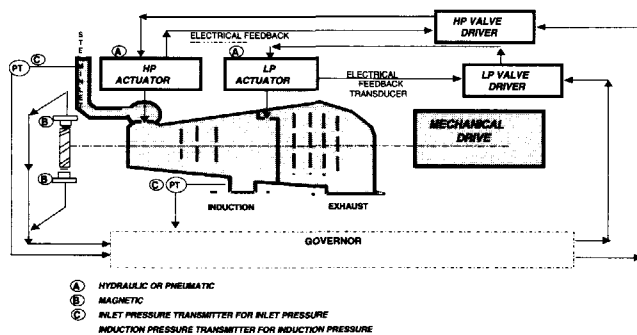


Figure 5. Multivalve Condensing Mixed Pressure Steam Turbine.

A noncondensing controlled extraction turbine bleeds part of the main steam flow at points downstream from the inlet. It is applied where heating or process steam is required at several different pressures with variable or intermittent flows. A condensing controlled extraction turbine bleeds off part of the main steam flow at a point downstream from the inlet. It is applied where heating or

process is required at a specific pressure below the inlet pressure. In both the noncondensing and condensing type units, a single or double controlled extraction may be considered, depending on the number of openings that steam exits the turbine prior to the exhaust (Figure 6).

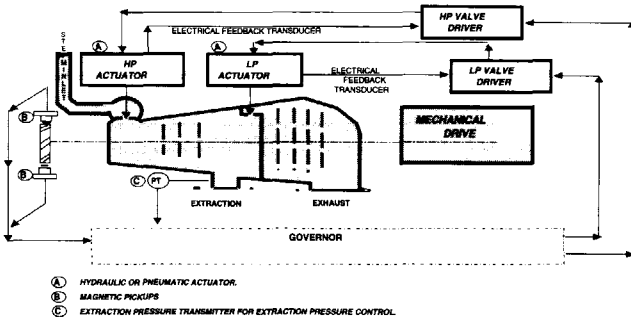


Figure 6. Multivalve Controlled Extraction Condensing Steam Turbine.

CONTROL VALVE AND RELAY VALVE ACTUATION

In most cases when utilizing an electric governor on a single valve unit, the means of valve actuation are either pneumatic or hydraulic actuators acting directly on the valve. Actual designs depend on the customer requirements, steam conditions, and the valve type. Figure 7 is an example of a direct acting governor valve design with a mechanical governor.

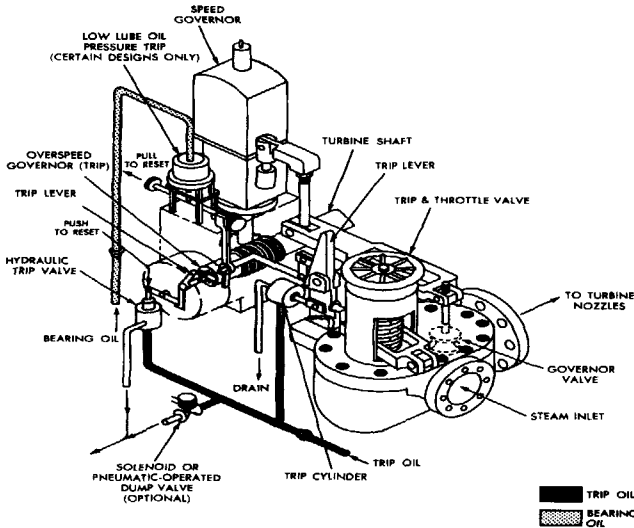


Figure 7. Direct Acting Governor Typical Trip and Control Schematic with Hydraulic Trip Arrangement.

A full oil relay is used on some single valve designs (depending on steam conditions) and the majority of multivalve steam turbines. Figure 8 incorporates a mechanical governor on a single valve unit in conjunction with a full oil relay system. Figure 9 incorporates an electric governor for a multivalve unit also utilizing a full oil relay system.

The type of hydraulic actuator that is most commonly used today is a torque-motor servo valve energized by the electronic control to generate a pressure differential applied to the ends of, and to operate, a second stage spool valve. Supply pressure is regulated by the spool valve to move a double acting servo piston and provide one inch of travel utilizing a minimum pressure of 120 psig and maximum in the 200 psig to 400 psig ranges.

The pneumatic actuator used in most cases is one that acts directly on the governor valves, and the movement is linear. It is a

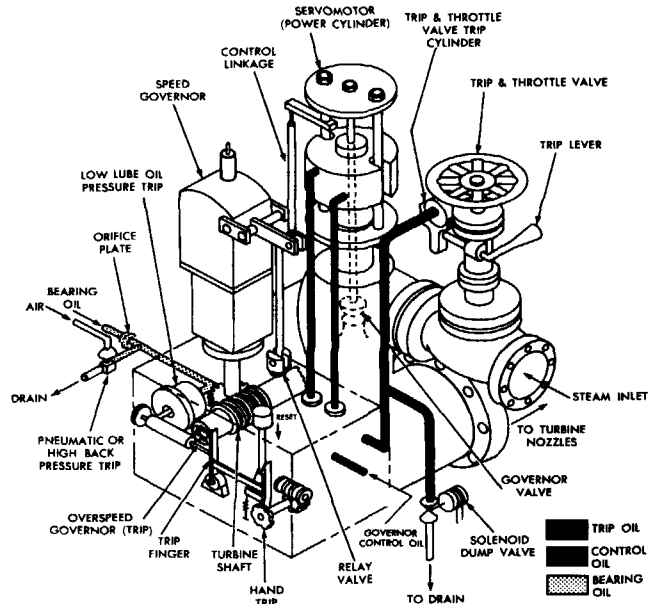


Figure 8. Full Oil Relay Governor Typical Trip and Control Schematic Relay and Trip Valves Integral with Bearing Cases.

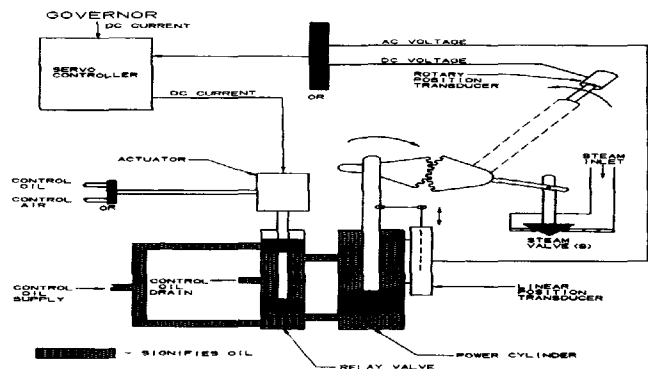


Figure 9. Electric Governor for a Multivalve Unit Utilizing a Full Oil Relay System.

powerful, high performance actuator that provides positive throttling of governor valves. The positioner supplies air to both sides of the piston, providing exceptionally stiff, precise movement, together with very high frequency response. A spring is provided to force the governor valve closed should the control signals to the actuator be lost. The spring closer system may also be utilized on a hydraulic actuator.

FEEDBACK SYSTEMS

The operation of a computer mouse is an excellent example of feedback. Figure 10 is a very simple block diagram of a person operating a computer mouse.

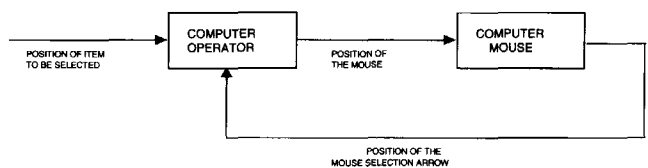


Figure 10. Block Diagram of a Person Operating a Computer Mouse.

The computer operator's sense of sight provides two input signals, these being the positions of the item to be selected and the

mouse selection arrow. The computer operator compares the two positions and moves the computer mouse as required, bringing the two together. The return loop (position of the mouse selection arrow) represents a fundamental concept of control known as feedback. Feedback may be defined as measuring the difference between an actual result and required result, then using the difference to move the actual result to the required result. In addition, a control system employing a feedback system is referred to as a closed loop system.

A steam turbine control system is a closed loop system that may be equated to the simple computer mouse example. Depending on the control required and the number of valves, however, a steam turbine may employ several control loops, each of which requires a feedback loop. Figure 11 is a block diagram of a multivalve steam turbine using two feedback loops.

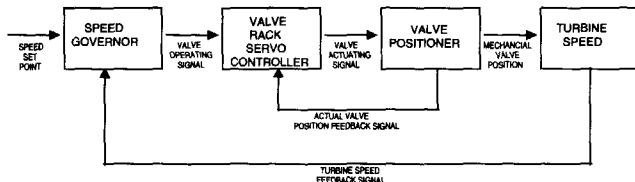


Figure 11. Block Diagram of a Multivalve Steam Turbine Using Two Feedback Loops.

When considering a governor retrofit, it becomes apparent from Figure 11 that there is more to the retrofit than simply selecting the correct governor. In this example, a selection must be made for the speed feedback and valve position feedback. The selection would get more complicated if the turbine is an extraction machine or if process control is required. Both the end user and the company doing the retrofit should be involved in selecting the feedback devices. This will ensure that the proper equipment is selected to meet the retrofit needs.

The first feedback device to be selected should be speed. This would be done with a magnetic pick up (MPU). The type of governor selected dictates the number of MPUs required. The original turbine supplier should be consulted to ensure that this required number could be installed on the machine. It is also important to keep in mind that many governor retrofits also include the conversion to an electronic overspeed trip system. Depending on the type of system chosen, up to three dedicated MPUs may be required for the overspeed system. The MPU installation would, of course, also include placing pick up gear on the turbine shaft. Again, the original equipment supplier should be consulted to advise proper shaft placement and gear type selected. The gear selected must meet the criteria for shaft size and rotational speed.

If the retrofit has process or extraction control requirements, feedback devices must be selected for this control also. Pressure transmitters must be selected for the proper range, accuracy, and environment. Again, the original equipment supplier should be consulted.

Finally, a feedback device may be required to provide valve position indication. This would be the case if the actuator did not operate directly on the turbine governor valve or valves. An example of this type of arrangement would be the full oil relay mentioned before. This is also known as a hydraulic, relay-servo system (Figure 9). Note that the actuator does not operate directly on the governor valve, but on a pilot valve. Therefore, an electronic servo-controller must be used to null the pilot valve after the control valve(s) has reached its final control position. The rotary or linear position transducer provides the feedback signal to the servo-controller to accomplish this task. The servo-controller processes the signal received from the position transducer and then sends a signal to the actuator nulling the pilot valve.

Another method of nulling the pilot valve would be by using mechanical feedback employing a return cam and/or a series of links and levers. This, however, has drawbacks such as increased maintenance and slower response. It is normally beneficial to remove

as much of the mechanical system as possible when doing an electronic governor retrofit. This again brings up the need to consult the turbine manufacturer. They will have the knowledge as to what parts of the system should be removed, replaced, or changed.

STEAM TURBINE CONTROL PROCESSORS

Part of any decision to do a control system retrofit includes the governor processor itself. To make the decision, one must consider the initial cost of the system and the desired reliability. Also considered should be the maintenance required for the system and the user's ability to handle the maintenance for complex systems.

A single processor is just what the name implies—a single controller for a single turbine. This control is adequate for most turbine applications where the user could tolerate a short down time while the governor is replaced. The single processor governor would most likely be of a lower price, and spare boards or even a spare governor could be stocked and replaced in a short time.

A fault tolerant governor is defined as a governing system that is capable of recovering from a fault by going to a backup system. A governing system with redundant processors is a common way of achieving some form of fault tolerance. In a redundant system, there are two processors, one of which monitors the health of the other. However, there is usually a third processor that is a supervisory system monitoring the health of both controlling processors. In either case, if a fault occurs, a transfer is initiated to the other controlling processor, allowing hot replacement of the faulty one. One point to keep in mind is that the device initiating the transfer may be considered a single point of failure even though the risk is small. To increase reliability, redundant systems may duplicate the input/output (I/O). The switch between processors is useless unless the I/O is duplicated. Experience has shown that most failures occur with the systems outside the governor, such as the I/O. It is therefore advisable to duplicate these also when considering a redundant system. This would include two, or dual, channel servo-controllers, two valve position transducers, and dual coil actuators. One can see from these requirements that any fault tolerant system will become expensive. The cost for a redundant system would typically be about four times that of a single processor system.

A true fault tolerant system employs three separate processors arranged in a voting logic (Figure 12). All three processors would simultaneously read and compare the same inputs and then run the same control program. Should one processor fail, the remaining two processors would provide continuous turbine control. Turbine control systems utilizing three processors generally approach near 100 percent reliability. The user is assured of an extremely low risk of any downtime due to a governor system failure. This system also allows hot replacement of the failed processor, like the duplex system. Also with this system, the user should consider cost. A fault tolerant system with three processors in a voting logic arrangement could cost up to eight times that of a single processor system.

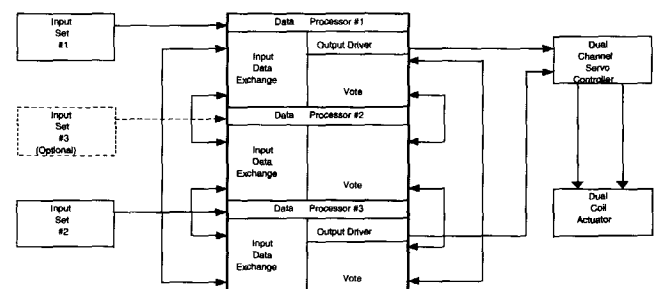


Figure 12. A Fault Tolerant System Employing Three Separate Processors Arranged in a Voting Logic.

PLC BASED CONTROL SYSTEMS

There has been an increased interest in programmable logic controller (PLC) based control systems for steam turbines because

of their ability to perform additional functions other than simple speed control. It must be remembered, however, that the processor controlling the speed loop must operate at the same cycle time as conventional governors. The steam turbine manufacturer should be consulted to ensure that the chosen PLC will safely control the steam turbine.

PLC control is a particularly desirable control for steam turbine driven synchronous generators because of their ability to perform several functions. Besides the basic speed/load control and cascade features of the conventional governor, the PLC can monitor generator parameters such as kilowatts, voltage, current, etc. Vibration and temperature may be monitored on the entire set and alarm status, and history can be provided for these points as well.

Remote communications can be another desirable feature of PLC control. A modem can be provided to allow real time monitoring and set point control of such parameters as speed, temperature, vibration, etc. This would be important in allowing the user or the equipment manufacturer to do trending and equipment troubleshooting.

OVERSPEED TRIP SYSTEMS

Any conversion to electronic steam turbine control should bring to mind electronic overspeed protection. All governor manufacturers recommend that the steam turbine be equipped with an overspeed shutdown device that operates totally independent of the governor. This device, known as the emergency overspeed governor, may be mechanical or an electronic device. It is set to operate at a predetermined speed, typically 110 percent of the maximum operating speed.

The total mechanical overspeed trip system generally consists of a spring-loaded plunger mounted in the end of the turbine shaft. When the overspeed set point is reached, the plunger actuates a system of linkage to close a trip valve. The mechanical trip system has drawbacks that can be solved with the use of an electronic system. These would include:

- Difficulty in changing trip settings
- Testing can only be done at high speeds by tripping the unit
- Stem has wearing parts
- Redundancy is not practical
- Repeatability of trip point is not accurate

The electronic overspeed governor does not have the disadvantages listed above and offers additional advantages. These would include simplex, duplex, and two of these voting systems. Some of these systems are also capable of recording the highest speed the turbine has reached.

MAINTENANCE

Scheduled preventive maintenance is essential for continued optimum performance and long service life of a steam turbine control system. The following is a general guideline of maintenance procedures that should be performed at six month intervals.

- Valve actuation assemblies (bar lift or camshaft) should be inspected and lubricated as recommended by the steam turbine manufacturer.
- Examine parts for damaged areas caused by corrosive fumes or process drippings. Clean and repaint these areas per the manufacturer's recommendations.
- If possible, stroke actuators and check for smooth actuation and full stroke operation.
- Check and tighten, as required, all linkage and mounting bolts.
- If possible, remove air, oil, and electrical supplies to verify the proper fail-safe action.
- Check and replace, as required, any rubber protection bellows.

- Check and replace any required control air/oil filter cartridges.

It is important to note that the service life of the actuator, whether air or oil, is increased with the use of a clean supply flow. Air actuators should operate on clean, dry instrument air. Hydraulic actuators should be supplied with clean oil filtered to a level as recommended by the manufacturer.

FIELD EXAMPLE

For the purpose of demonstrating what components are additionally required and which ones are no longer required, a multivalve controlled extraction unit is utilized in this example (Figure 6). This type of turbine consists essentially of a high-pressure section and a low-pressure section, the extraction steam being taken from a chamber between the two sections. The turbine is equipped with an automatic mechanism for extracting steam at the desired pressure. This mechanism is interconnected with the main speed governor of the single automatic extraction turbine. Constant pressure is maintained in the extraction line by governing the amount of steam that passes from the high-pressure section to the low-pressure section. The extraction control system maintains constant pressure in the extraction line, regardless of changes in load or extraction steam requirements. Assume horsepower is constant and there is an increase in demand for extraction steam. To allow for this additional flow, the inlet valves open to let more steam into the turbine. At the same time, the extraction valves close so that extraction flow is increased by reducing flow to the low-pressure section of the turbine. This reduction is in such proportion that additional horsepower increase in the high-pressure section equals the horsepower reduction in the low-pressure section. Thus, the speed remains constant. As the demand for extracted steam decreases, the pressure regulating system closes the inlet valves and opens the extraction valves in the opposite manner. The low-pressure section carries an increase in load equal to that given up by the high-pressure section. All these complicated control algorithms that limit and ratio the two valve rack control systems are completed within the digital governor.

There are a number of digital governors on the market today that are fully acceptable to control a turbine of this type. It is up to the end user, the turbine manufacturer, and the control system supplier to decide the most operationally correct, the most cost effective, and the most reliable governor for the application. The main area of consideration, after selecting the control vendor and the components to make up the system, is exactly what is required during the outage. Table 1 indicates the devices required for this retrofit illustration that may range in cost from as low as \$100,000 to as much as \$250,000, depending on the chosen system. Figure 13 shows a drawing of the example turbine prior to the retrofit, with all the linkage and mechanical feedback on the unit. Much of the equipment needed to control the turbine prior to the conversion may now be removed and the unit cleared of many moving parts, as can be seen in Table 2 and Figure 14. With the removal of the wearing parts and the clearing of the turbine bearing case, the unit is more reliable and easier to work on.

SUMMARY

There are many areas of concern that a user must be aware of in deciding if a new governor system is required, what type of system will satisfy the process application, and what possible future requirements will be necessary. These particular areas can, and in most cases will, require time and effort in order for the steam turbine user to make the correct decision for the application. In Tables 3, 4, and 5, a systematic approach to the selection of a control system is presented.

Table 3 (Siedow, 1997) indicates whether there is a problem or a potential problem with the existing governor control system. After this quick evaluation, it may be possible for an end user to establish if the governing system is in need of maintenance, refurbishment, or a new system retrofit.

Table 1. Parts Required for an Electric Governor Conversion.

Control panel
Governor
Inlet valve control board
Extraction valve control board
Magnetic pickups
Magnetic pickup brackets
Magnetic pickup gear
Pressure transducer
Inlet valve relay/hydraulic actuator
Extraction valve relay/hydraulic actuator
Inlet valve actuator bracket
Extraction valve actuator bracket
LVDT for high-pressure valves
LVDT for low-pressure valves
LVDT brackets
Proper inlet gain relay
Proper extraction gain relay
Control oil system
Terminal boxes
Wiring schematics
Piping schematics
Assorted wire and conduit
Assorted piping

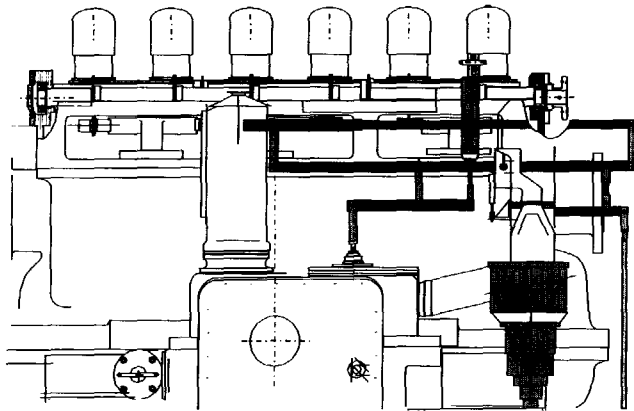


Figure 13. Mechanical Governor System.

The majority of Tables 4 and 5 are constructed as a series of questions that the prime mover user can ask himself or herself prior to involving the turbine manufacturer or the control manufacturer, in an attempt to establish the specification requirement for the future retrofit.

If this information is considered and followed through the investigation phase, the procurement phase, the checkout, and installation phase, it may help to prevent potential major problems from occurring.

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Table 2. Mechanical Parts That May Be Removed for Retrofit.

Mechanical governor
Governor drive gear
Governor drive shaft
Governor worm gear
Inlet valve rack relay linkage
Inlet valve rack return linkage
Inlet valve rack return cam
Inlet valve rack collapsing link
All inlet valve rack linkage pivot brackets
Extraction pressure controller
Extraction pressure controller linkage
Inlet to extraction valve coupler linkage
Extraction valve rack relay linkage
Extraction valve rack return linkage
Extraction valve rack return cam
Extraction valve rack collapsing link
All extraction valve rack linkage pivot brackets
All inlet/extraction valve rack ratio linkage and adjusting devices
All inlet/extraction valve rack limiting linkage and adjusting devices

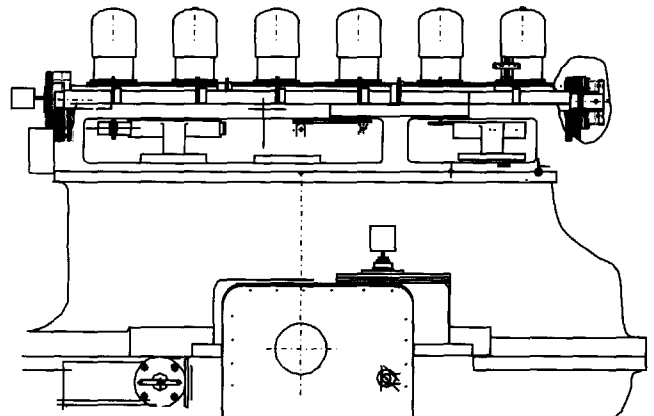


Figure 14. Electrical Governor System.

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Table 3. Systematic Approach to Selection of a Control System.

Is the present day control system operating in a satisfactory manner?
No.

Is the system unstable?
Yes.
Is the governor system worn out?
Was the governor system designed poorly?
No.

Is the response of the system a problem?
Yes.
The response is too quick.
The system is upset easily and is over-sensitive.
The response is too slow.
The speed swings too much with a change in load.
The unit overspeeds on loss of load.
No.

Is the reliability of the system a problem?
Yes.
System shuts down unexpectedly.
The repair cost is too high.
The down time is too long.
The system is down too often.
Yes.

Is the system outdated?
Yes.
It is very difficult to get spare parts.
The OEM is out of business.
No.

Is the system inadequate for automation?
Yes.
Additional monitoring information is required.
Remote control is required.
Requires integration with automatic plant system.
No.

Is energy conservation an issue?
Yes.
Fuel savings.
Better control to improve turbine efficiency.
No.

Is the goal to automate and reduce manpower?
Yes.
In the maintenance area.
In the operations area.

Table 4. Questions to Be Considered.

I. How is the plant now configured?

1) What types of units are in the plant at the present time?
A) Steam turbines _____
B) Gas turbines _____
C) Diesels _____
D) Compressors/Pumps/Fans/Generators _____
E) Others _____

2) What types of governors are on all the prime movers at the site?
A) Electrical
a) Woodward _____
b) Tri-Sen _____
c) CCC _____
d) ETSI _____
e) Prime mover OEM _____
f) Others _____
B) Mechanical
a) Woodward _____
b) Prime mover OEM _____
c) Others _____

3) What control modes are required for the prime mover that is to be retrofitted and the other prime movers at the site?
A) Speed _____
B) Load _____
C) Pressure _____
a) Inlet steam/Extraction steam/Induction steam/Exhaust steam/Suction/Discharge, etc. _____
D) Others _____

4) Do I have other prime movers controlling the same modes as the retrofitted machine? _____

5) What control modes work best for this plant? _____

6) What type of (generator/fan/compressor, etc.) control is operating today and what is required for the future?
A) Pressure _____
B) Speed _____
C) Load _____
D) Others _____

7) If multiple units are to be retrofitted, how are the current units operating together?
A) Generator drives
a) Isolated from utility _____
b) Tied to utility _____
B) Mechanical drives _____

II. What are the basic requirements for the retrofitted unit?

1) What is required of the prime mover to control? _____

2) Are the other prime mover control systems compatible with the new one(s)? _____

3) What is the prime mover control mode priority? (one control mode/one valve)
A) Speed/Load/Suction pressure/Discharge pressure/Inlet steam pressure/Extraction steam pressure/Induction steam pressure/Exhaust steam pressure _____

4) What control system will fit my application reliably, functionally, and economically?
A) Governor
a) Electrical
1) Woodward 2301/2500/501/503/505/507/509/511/5000, etc. _____
2) ETSI _____
3) Tri-Sen 300/310/410/500/1000/3000, etc. _____
4) CCC _____
5) Other _____
B) I/O requirements
a) Analog _____
b) Digital _____
C) Actuator
a) Hydraulic _____
b) Pneumatic _____
D) Feedback, if required
a) Electrical _____
b) Mechanical _____

5) Generator drive (synchronous)
A) How should this retrofitted prime mover run?
a) Isolated from utility _____
b) Connected with utility _____
B) How many prime movers have to run isolated simultaneously? _____
C) Which prime mover should be the lead machine while isolated? _____
D) How many prime movers have to have isochronous load sharing? _____
E) What control modes should the prime mover control when isolated? _____

III. What are other control system considerations?

1) Should the control system be an analog or a digital control? _____

2) Should it be a redundant control system? _____

3) What is the most reliable source of power to run this control system? _____

4) Should the control system do any supervising functions? _____

5) How should the trip logic function? _____

6) Who is actually going to do this retrofit?
A) The specification and ordering _____
B) Wiring drawings _____
C) The operational instruction books _____
D) The installation _____
E) The check out _____
F) The operator training _____

Table 5. Areas of Concern.

1	Plant control modes that are required of the prime mover
2	Compatibility of new system with existing ones
3	Governor (control system) to do the job
4	Control manufacturer that you are comfortable with
5	DCS interface
6	Remote control
7	Input/output requirements
8	Redundance
9	Battery backup
10	Area requirement of equipment
11	Actuator to do the job
12	The reliability of the system
13	Uninterruptible power supply
14	Importance of linkage and valve settings
15	The gain of mechanical portion of the system
16	Coordination of the retrofit
17	Generator control requirements
18	Longer lead times for complicated system