Turbine, Generator & Auxiliaries - Course 134

TURBINE OPERATIONAL PERFORMANCE

The purpose of any steam power plant is to convert heat energy released by the fuel into generator electrical output. Under the best circumstances this process is rather inefficient. In a typical CANDU generating station something on the order of 70% of the heat generated in the reactor is lost through the production of waste heat and through internal electrical power requirements. The ability to produce higher temperature superheated steam, allows conventional fossil fuel steam plants to be somewhat more efficient but even in these plants only about 40% of the heat energy is converted to electrical output from the generator.

Because the conversion of heat energy to electrical energy is at best rather inefficient and because the conversion process involves a great potential for a degrading of even this efficiency, steam plant operators have long been concerned with assessing the amount of heat energy required to produce a kilowatt-hour of electrical output. The amount of heat energy which must be produced in fuel burnup to produce a kilowatt-hour of electrical output is known as the station heat rate and the operator who saw an upward trend in this station heat rate was concerned not only because of wasted fuel dollars but also because it indicated something unpleasant was happening to his plant.

Theoretically the computation of a station heat rate for a nuclear generating station is simpler than for a conventional plant. The reason is that no conventional plant operator knows as much information about his heat source as a nuclear operator does. For reactor control and regulation the precise power level in the reactor must be known at all times. For a reactor operating at a constant power level the number of kilojoules of heat energy produced in an hour is simply

$$\frac{KJ}{hr.} = (\text{Thermal MW power})(3.6 \times 10^{6}\ KJ/MW\text{-}hr.) \qquad 2.1$$

The station heat rate, SR, can, therefore be easily computed by the following formula:

$$SR = \frac{KJ}{KW\text{-}hr}\ \text{output} \qquad 2.2$$

If a nuclear generating plant produces 1743.5 MW of thermal power in the reactor and 543 MW of electrical output, then the station heat rate can easily be computed as:

$$SR = \frac{(\text{Thermal MW power})(3.6 \times 10^6 \text{ KJ/MW-hr})}{\text{KW output}}$$

$$= \frac{(1743.5 \text{ MW})(3.6 \times 10^6 \text{ KJ/MW-hr})}{(543{,}000 \text{ KW})}$$

$$= 11559.1 \text{ KJ/KW-hr}$$

It does not require any particular insight to realize that if this value increases to 11,609.1 KJ/KW-hr, or by about .4%, then the plant is operating less efficiently, fuel is being wasted, and plant components are being taxed unnecessarily.

The problem comes in the fantastically inexpensive cost of nuclear fuel. The 1976 cost of CANDU nuclear fuel is only about $ .07 to $ .12 per 1,000,000 KJ. This should be compared to $ .60 to $ .90 for coal and $1.80 to $2.20 for oil. Although these values will undoubtedly change rapidly, the relative standing should remain nearly constant. Thus over a year, the inefficiency described above would cost the oil fired station about $450,000, the coal fired station about $170,000 and the nuclear station about $20,000. It should come as no surprise that you can get a lot more excited about a .4% increase in station heat rate at a conventional generating station than at a nuclear generating station.

The obvious economic conclusion of this is that based on fuel costs you cannot justify the expense of vast sums of money tracking down inefficiencies in a nuclear generating station. On the other hand there is another implication to an increasing heat rate. If the station heat rate is increasing then something is not working as it should. As the efficiency of the plant decreases due to a gradual deterioration of component capabilities, the probability of a forced outage increases. In the event the plant must be shutdown for required maintenance, the cost of alternate energy sources to replace the megawatt hours of lost electrical output can be staggering. At the time of this writing the estimated cost for alternate energy for a Pickering size nuclear generating station is on the order of $5,000 per hour. This figure depends on the cost differential between conventional and nuclear fuel but it is doubtful it will decrease over the foreseeable future.

The typical nuclear station is thus faced with a delemma, the horns of which are a very marginal rate of return on dollars invested for improvement in plant efficiency and a truly tremendous cost for an unplanned plant outage. It should be reasonably obvious that the tradeoff in dollars between these two extremes is a major challenge.

The practice of assessing steam plant operational performance as a method of determining the condition of the unit is fundamental to lengthing the time between major overhauls while avoiding a forced outage. However there are several factors which complicate the assessment of the condition of an operating turbine unit which deserve some attention.

Accuracy and Adequacy of Instrumentation

Once the operator has detected a trend of increasing station heat rate he is faced with the dual problems of first determining precisely where the problem lies and second deciding whether the problem justifies the expenditure of down time and maintenance dollars to correct it. The ability to trace a deteriorating heat rate to its ultimate cause requires the ability to determine accurately the actual conditions at various locations. This is often difficult and occasionally impossible using existing instrumentation. For example, to assess the condition of the turbine unit it is desirable to determine the heat energy delivered to the unit per kilowatt-hour of electrical output. The Turbine Heat Rate (THR) can be determined by the formula:

$$THR = \frac{M_1(h_s - h_{fw}) + M_2(h_2 - h_1)}{KW} \qquad 2.3$$

where:

M_1	= steam flow through the stop valve	(KJ/hr)
h_s	= steam enthalpy at the stop valve	(KJ/Kg)
h_{fw}	= enthalpy of final feedwater	(KJ/Kg)
M_2	= steam flow through reheater	(Kg/hr)
h_2	= steam enthalpy from reheater	(KJ/Kg)
h_1	= steam enthalpy to reheater	(KJ/Kg)
KW	= total electrical output in KW	

In analyzing this theoretically rather simple formula it becomes obvious that the accurate determination of turbine heat rate using this formula requires the steam flow at two points as well as four steam enthalpies three of which require steam quality determinations. Before applying this formula these quantities must be known with sufficient accuracy to yield an accurate turbine heat rate. If the steam flows can only be determined within ± 5%, then the probability of correctly detecting changing unit efficiency is rather doubtful. While necessary parameters can often be estimated or derived from other parameters, this is at best often difficult and the installation of permanent or portable accurate instrumentation may well be the only way to assess unit performance properly.

Reproducibility of Initial Conditions

Although a variety of conclusions can be drawn from an increasing net station heat rate, one has to be careful not to be chasing a will-o'-the-wisp. A large number of factors can effect the net station heat rate which have little or nothing to do with a deterioration of the turbine or steam/feedwater system performance. Whenever a heat rate is conducted it is absolutely essential that uniform initial conditions be utilized on which to base comparisons. Normal variations in condenser vacuum, makeup water flow, steam pressure, steam generator level, adjuster rod motion, xenon inventory, generator hydrogen purity and heat transport temperature can result in hours of searching for nonexistent problems.

The method of turbine unit analysis which can yield the most productive results is based on initial conditions which are reasonably easy to reproduce. Full power with the steam and feedwater system in a "normal lineup" will probably result in the fewest induced errors. In addition these conditions should be held constant for some time interval - say five or ten minutes - prior to taking the heat rate data.

The following is a partial list of conditions which should be met prior to conducting a heat rate determination.

(1) generator producing approximatlly 100% of rated gross output

(2) steam flow from steam generators equal

(3) feed flow to steam generators equal

(4) xenon at 100% equilibrium

(5) steam generator levels constant

(6) condenser vacuum at some reference level

(7) reactor reactivity at equilibrium condition

(8) generator hydrogen purity at some reference level

(9) heat transport temperature constant

(10) steam pressure constant

(11) no steam generator blowdown in progress

(12) no steam flow to bulk steam plant or through reject system

The precise initial conditions and acceptable range of parameters should be specified for a net station heat rate. In addition, if these conditions cannot be met the quality of the heat rate will be downgraded.

Frequency of Heat Rate Determination

A detailed determination of heat rates on the various components of a generating station is the most accurate method of measuring turbine unit performance and assessing the proper operation of the turbine and its auxiliaries. However, this can be expensive in both time and manpower. For this reason it is generally considered good practice to carry out such tests only once per year and during pre- and post-overhaul tests. On the other hand, when heat rates are computed infrequently it is likely that comparability of results suffers. What probably represents the best compromise is frequent calculalions of net station heat rate using equation 3.1 to insure reproducibility of results and to detect any major changes, and to conduct a detailed heat rate at annual intervals. The net station heat rate conducted at the time of the detailed analysis could then be used to check reproducibility.

Turbine Heat Rate

Once a change has occurred in station heat rate, it becomes necessary to make a determination of the implication of the change. Generally this implication can fall into the following four categories:

(a) insignificant

(b) correct the problem without shutting down the turbine

(c) correct the problem including shutting down the turbine

(d) correct the problem during the next scheduled turbine outage.

The classification into one of these categories can logically occur only by knowing what is causing the change in heat rate. Since station heat rate is effected by a wide variety of things from the reactor to the generator, the problem becomes one of localization of cause.

Turbine heat rate is defined as the number of Kilojoules per hour delivered to the turbine unit per Kilowatt of generator electrical output. As such it is sensitive only to changes occuring in the steam/feedwater system and is independant of problems associated with the reactor, heat transport system and steam generators.

Turbine heat rate is computed from equation 2.3.

$$THR = \frac{M_1(h_s - h_{fw}) + M_2(h_2 - h_1)}{KW}$$

where: M_1 = steam flow through the stop valve (Kg/hr)
h_s = steam enthalpy at the stop valve (KJ/Kg)
h_{fw} = enthalpy of final feedwater (KJ/Kg)
M_2 = steam flow through reheater (Kg/hr)
h_2 = steam enthalpy from reheater (KJ/Kg)
h_1 = steam enthalpy to reheater (KJ/Kg)
KW = total electrical output in KW

Referring to the diagram 2.1 you will notice that Turbine Heat Rate would be computed as:

$$THR = \frac{(108.0)(3600)(2793.39 - 726.23) + (88.352)(3600)(2793.39 - 1103.98)}{790699}$$

$$= \frac{8.0645 \times 10^9 + .5373 \times 10^9}{790699}$$

$$= \frac{8.6018 \times 10^9}{790699}$$

= 10878.7 KJ/KW-hr

In lieu of equation 2.3 turbine heat rate can be computed from the following:

$$THR = \frac{M_3 h_s - M_4 h_{fw} - M_5 h_{rhd}}{KW} \qquad 2.4$$

where: M_3 = steam flow from steam generator (Kg/hr)
h_s = steam enthalpy from steam generator (KJ/Kg)
M_4 = feedwater flow (Kg/hr)
h_{fw} = enthalpy of final feedwater (KJ/kg)
M_5 = reheater drain flow (Kg/hr)
h_{rhd} = enthalpy of reheater drains (KJ/Kg)
KW = total elecrical output in KW.

The choice of equation 2.3 or 2.4 will depend largely on the accuracy to which the parameters used in the equations can be determined. In either case, the accurate determination of flow rates is probably the most limiting factor. From an operational standpoint equation 2.4 is probably the most convenient and can be further simplified by making some assumptions.

Since liquid flow can generally be determined more accurately than vapor flow it is often easier to approximate M_3 as the sum of M_4 and M_5. In addition since the enthalpy of saturated steam at steam generator pressure, it can often be treated as a constant Equation 2.4, therefore, becomes:

$$THR = \frac{M_4 (h_s - h_{fw}) + M_5 (h_s - h_{rhd})}{KW} \qquad 2.5$$

where: h_s = steam enthalpy of saturated steam at the design steam generator pressure. (KJ/Kg).

Since the majority of the heat energy loss (roughly 90%) occurs in the steam/feedwater system, a change in turbine heat rate is reflected virtually one to one in station heat rate. This means if turbine heat rate increases by .5% we would expect an increase of about .5% in station heat rate.

Once the cause for increasing station heat rate has been tracked to the steam/feedwater system, the problem is "simply" one of tracking down the particular offending component.

Condenser Backpressure

If the condenser back pressure increases, the turbine output will decrease and turbine heat rate will increase. Figure 2.2 shows this effect. The result has such a great impact on turbine heat rate, that two otherwise comparable turbine heat rate determinations with differing condenser vacuums will yield widely different results.

At a constant power level an increase in condenser back-pressure can be caused by only four things:

(a) increase in the average temperature of the condenser cooling water in the tubes

(b) flooding of the condenser tube surfaces due to high hotwell level

(c) air leakage into the shell of the condenser

(d) a decrease in the overall heat transfer coefficient of the tubes.

The cooling water temperature will vary considerably between summer and winter. Under normal conditions, however, the temperature rise across the condenser is reasonably constant. This can be seen from the formula expressing the heat rejected to the condenser cooling water:

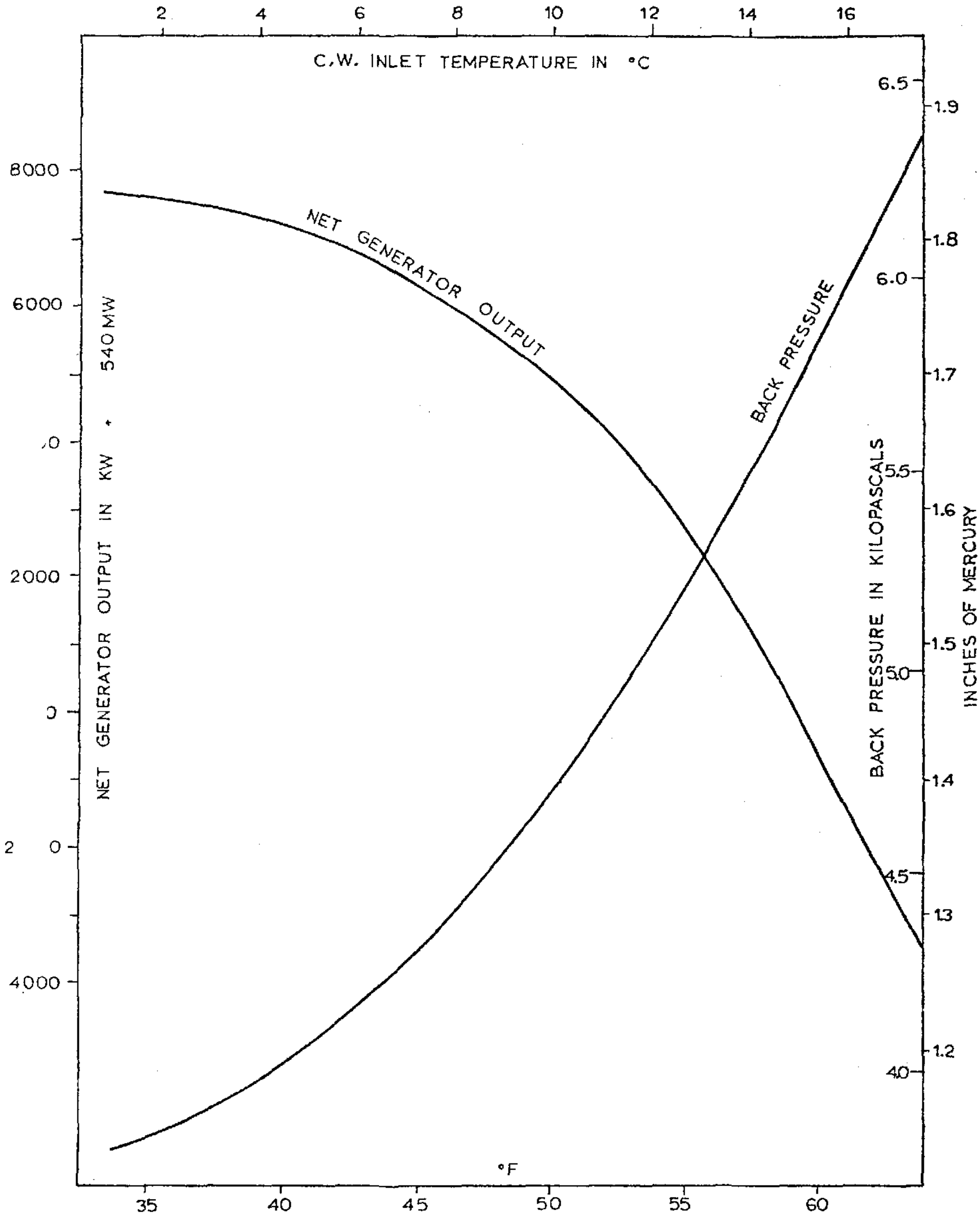
$$\overset{\circ}{Q} = m \, Cp \, \Delta T \qquad 2.5$$

where: $\overset{\circ}{Q}$ = the heat rejected to the ccw (KJ/sec)

m = ccw flow (Kg/sec)

Cp = the constant pressure specific heat capacity of water (KJ/Kg°C)

ΔT = the temperature rise in ccw across the condenser (°C)



Effect of Cooling Water Temperature on Back
Pressure and Net Output of Pickering G.S.

If the rate at which heat is rejected and the ccw flow rate remain constant, the ccw ΔT will remain constant. At a constant generator power, the rate at which heat is rejected to the ccw is reasonably constant for small changes in condenser vacuum. This implies that if vacuum is decreasing and condenser ΔT is remaining constant, then the cause is possibly an increase in the temperature of water entering the ccw system from the lake. This can be easily checked by monitoring ccw inlet temperature.

A change in lake water temperature usually occurs due to seasonal or diurnal fluctuations. Occasionally, however, a high wind has produced a sufficient current to return the water at the condenser outlet back into the ccw intake with a resulting rapid increase in ccw temperature.

Other factors which increase the average temperature of the condenser cooling water in the tubes are usually associated with a decrease in ccw flow from such causes as cavitation or air binding of the ccw pumps, marine growth in the condenser tubes, sand in the condenser tubes, blockage of the screens or tubes with debris, and air binding of the tubes or water boxes.

Returning to equation 2.5 you will notice that if the ccw flow rate decreases while a nearly constant rate of heat rejection is maintained then the ccw ΔT will increase.

$$\overset{\rightarrow}{\overset{\circ}{Q}} = \overset{\downarrow}{m}\, Cp\, \overset{\uparrow}{\Delta T}$$

The implication is that if vacuum is decreasing and ccw ΔT is increasing then there is a decrease in ccw flow. A decrease in ccw flow can be particularly troublesome if it results in a partial blockage of some tubes. This will increase the ccw flow through the remaining clear tubes with possible tube cavitation and failure resulting.

Air inleakage to the condenser will lower the condenser vacuum (increase the backpressure). However, since the increase in backpressure is attributable to air pressure as opposed to steam pressure, the temperature of the condensing steam (condensate temperature) will not rise appreciably as the backpressure increases.

A good measure of the tightness of the condenser and associated subatmospheric systems is the dissolved O_2 level in the condensate leaving the hotwell. If this level is rising then regardless of what is happening to condenser vacuum air is getting into the system. This additional air ingress can occur either from increased leaks or decreased air extraction capability. In either case the cause of the problem must be found and corrected not only to eliminate the inefficiencies caused by increased backpressure but because the long term effects of general and localized corrosion on the condensate, feedwater and steam generator will eventually produce significant problems.

If the overall heat transfer coefficient of the tubes decreases due to corrosion, scaling or fouling of the tube surfaces, the effect is quite similar to air ingress. Condenser Cooling Water ΔT remains constant and backpressure increases. However, since the increase in backpressure is attributable to steam pressure as opposed to air pressure, the condensate temperature will rise corresponding to the saturation temperature for the condenser backpressure. In addition, the condensate dissolved O_2 will not change if the cause of the vacuum decrease is not air.

The below table summarizes the type of parameter changes for various conditions affecting vacuum:

CAUSES OF POOR PERFORMANCE OF CONDENSER

SITUATION	CCW INLET °C	CCW OUTLET °C	CCW ΔT °C	BACK-PRESSURE KPa(a)	SATURATION TEMPERATURE CORRESPONDING TO BACK-PRESSURE °C	CONDEN-SATE TEMP. °C
Normal Operation	15.0	25.0	10.0	4.50	31.0	31.0
Decrease in ccw Flow	15.0	30.0	15.0	5.17	33.5	33.5
Increase in ccw Inlet Temp.	20.0	30.0	10.0	5.94	36.0	36.0
Air Leakage	15.0	25.0	10.0	6.27	37.0	31.5
Tube Surface Fouling	15.0	25.0	10.0	5.17	33.5	33.5

Feedwater Heating System

The feedwater heating system can be the source of a significant increase in turbine heat rate. Turbine heat rate is particularly sensitive to final feedwater temperature and a 3°C change in final feedwater temperature can affect turbine heat rate by as much as .2%. Generally the performance of the feedheating system can be monitored by watching:

(a) the final temperature of feedwater leaving each feedheater, and

(b) the terminal temperature difference between extraction steam and feedwater leaving the heater.

If these parameters remain close to those of the design heat balance then there cannot be too much wrong with the system.

When one feedheater does not raise the feedwater at the outlet to the design value, then the next feedheater will require more extraction steam if this temperature loss is to be regained. Because this additional extraction steam is taken from a point nearer the steam generator, energy which is normally utilized in the turbine is bled off as extraction steam. For a constant load output under these conditions, additional steam to the high pressure turbine is required and turbine heat rate increases.

The following problems are likely to encompass the majority of feedheating system deficiencies:

(a) Long term contamination of feedheating surfaces. This can occur due to oil ingress from the turbine or buildup of corrosion products.

(b) Extraction steam valves not fully open.

(c) Insufficient venting of the feedheater shell. This can be caused by fully or partially shut valves in the vent lines.

(d) Increased level in the feedheater shell. This floods out some of the tubes and reduces the heat transfer area.

(e) Tube blockage due to foreign material in the feed-lines.

(f) Changes in extraction steam pressure or quality due to problems in the turbines. If the enthalpy of the extraction steam decreases then the flow of extraction steam will increase.

By carefully analyzing the feedwater ΔT and Δp, the terminal temperature difference, the feedheater shell pressure, and the shell drain temperature and comparing these parameters with design values, the cause of the deficiency in feedheater performance can be localized.

Turbine Internal Efficiency

The primary causes of a reduction in internal efficiency are:

(a) chemical deposition on turbine blades,

(b) increase in blade tip clearances due to erosion or physical contact between fixed and moving parts,

(c) changes in blade surface.

Because of wet steam conditions in the high pressure turbine, low steam generator pressure (and, therefore, temperature), and the shift to volatile steam generator chemistry, chemical deposition on turbine blading is not frequently a cause of loss of turbine efficiency on nuclear steam turbines. There have been cases of chemical corrosion of blading due to steam generator carryover in plants using solid steam generator chemistry and, therefore, the effects of possible chemical attack cannot be completely ignored.

Tip rubbing can be minimized by careful adherence to run-up and loading procedures and avoidance of conditions likely to produce excessive differential axial and radial expansion between the casing and rotor. Control of excessive blade erosion due to wet steam or standing water conditions is largely a design problem related to adequate moisture removal from each stage. However, errors in design such as improper sizing of stage drains and inadequate ability to remove moisture from moving blades can cause significant decreases in efficiency due to erosion.

With the wet steam conditions which exist in a nuclear steam turbine, the blades will gradually be eroded due to moisture impengement. This damage is usually most severe in the high pressure turbine and latter stages of the low pressure turbine and usually first affects the trailing edge of the front side of fixed blades and the leading edge of the back side of moving blades. The result of this erosion is that the profile and surface of the blade will change with time. If the wear becomes extensive, the blades may change to the extent that stage efficiency is reduced. It is very difficult to detect such blade wear without shutting down the turbine and examining it internally. However, careful observation of the pressure drops across a stage or group of stages may make the change apparent.

It is more likely in practice that if the blade wear is such that there is a noticeable increase in steam consumption, it will show up in the form of excessive vibration due to the out-of-balance of the blade wheels.

Steam Generator - Water Chemistry

Removal of impurities in the steam generators can have an effect on station heat rate because hot water lost through blowdown must be replaced through cold makeup water. If the amount of blowdown is significant, there may be a noticeable effect on station heat rate, however, this effect is far out weighed by the consequences of running with out-of-specification steam generator chemistry.

The long term effect on heat rate through tube fouling, turbine blade deposits or derating far exceeds the advantage gained by minimizing blowdown. Each out-of-specification condition is significant and the cause should be rapidly corrected to avoid both the short and long term effects.

Gland Steam Consumption

Problems in the gland seal system are usually not sufficient to cause a noticeable increase in turbine heat rate. Since only about.08% of the steam flow from the steam generators is used to seal the turbine glands, the effect on heat rate is minimal. However, steam flow to the glands is a good indicator of the basic condition of the gland and for this reason can be valuable in diagnosis of gland problems.

Deterioration of turbine labyrinth glands usually occurs from thermal bending of the shaft or radial rubbing in the glands during startup. These problems can cause significant vibrations on startup but tend to become self limiting as the unit speed is increased above the critical speed and the unit warms up. This is particularly true of radial rubbing and as a result gland deterioration can occur without the operator being fully aware of the problem.

The problems can be largely eliminated by:

(a) correct operator interpretation of vibration on startup,

(b) correct steam to rotor and steam to casing differential temperatures,

(c) avoidance of low bearing oil temperature,

(d) avoidance of prolonged low speed operation, and

(e) proper alignment of rotor and casing during overhaul.

Providing the turbine unit is reasonably free of air leaks, the level of dissolved oxygen in the condensate, the length of time to draw a vacuum, and the length of time to lose vacuum when the air extraction system is shutdown are good measures of the condition of the gland.

Derating

Derating of a generating station is the process of restricting generator output below full power because of some abnormality in the system. Because the generating station is forced to run at less than its design capability, derating can have a significant effect on station heat rate.

The ultimate derating occurs when the heat source system is no longer capable of producing safely the number of kilojoules per hour required to produce the generator design output. In the case of a reactor there is an absolute upper limit to power output. Although the generating station is designed to allow some increase in station heat rate before reaching this upper limit, a decreasing station efficiency will eventually reach the point where the reactor plant reaches its limit before the generator gets to 100% of its design output.

When this occurs there are only two possible alternatives:

(a) increase the design capability of the reactor, and thereby allow the reactor to produce more power by lowering the safety margin. This, of course, would require consultation with the reactor designer and with the AECB to obtain consensus that the reactor plant was overdesigned in the first place.

(b) find and correct the cause of the increasing station heat rate so that the reactor can once more produce design generator output within design reactor specifications.

Deratings of a more temporary nature may occur when the generating station cannot be safely operated at 100% of design generator output. While the problems in the conventional end of a nuclear station which may result in derating are almost endless, the following have been occasional sources of deratings.

Condenser Circulating Water ΔT

To limit algae growth in the vicinity of the outflow, environmental authorities have imposed a limitation of 10°C on the temperature differential of the CCW across the condenser. Inability to meet this limit at full power necessitates a derating until the temperature rise is within the limit. In the case of some older stations, the limit was imposed after the station was built and has resulted in what amounts to permanent derating.

Generator Hydrogen Pressure

Loss of hydrogen from the generator results in a decrease in effective generator cooling and an increase in generator temperatures. The generator manufacturer specified maximum generator ratings for various values of hydrogen purity and pressure. In addition there are limits on stator and rotor temperatures which could be exceeded under full generator load with less than design hydrogen pressure. For these reasons if it is impossible to maintain hydrogen pressure at the design value for the rated load, the unit would have to be derated.

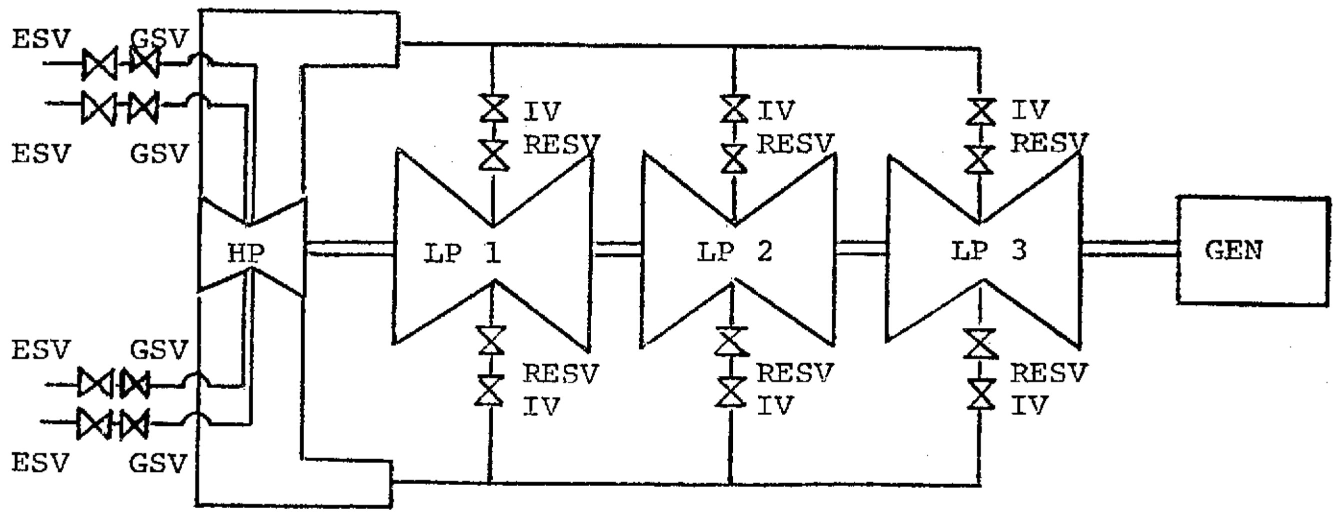
Feedheaters in Service

In addition to improving the efficiency of the steam cycle as described in the last lesson, the feedheating system is necessary to protect the steam generators from several hazards. If the temperature difference between the incoming feedwater and the water in the steam generator is excessive, there may be significant thermal stresses set up in the preheater, tubes, tubesheet and other structural members of the steam generator. These stresses can cause a shortening of steam generator life through fatigue, or if the stresses are severe enough, cause tension failure of the stressed members. For this reason, the feedheating system must heat the feedwater to a sufficient temperature to lower this ΔT and, therefore, the resulting stresses to within design limits.

If some feedheaters are out of service, the remaining feedheaters may not be able to raise the final feedwater temperature to a sufficiently high value to allow an acceptible ΔT between the feedwater and the generators. In this case the feedwater flow would have to be reduced to allow the available feedheaters to raise the final feedwater temperature to within an acceptible ΔT. This problem has been minimized by having two banks of feedheaters either one of which can supply full feedheating capability. However, during "poison prevent" operation when extraction steam is unavailable and the deaerator provides the only effective feedheating, the requirement to heat feedwater above a specified lower limit imposes a very real limit on plant operation.

Turbine Steam Control Valve Operation

Figure 2.3 shows a typical large turbine unit and the associated control valves. These valves are designed to control the steam supply to the turbine under a variety of normal and casualty conditions. If one of these valves was inoperative the unit might not be able to supply safely 100% of rated load.



ESV = Emergency Stop Valve
GSV = Governor Steam Valve
IV = Intercept Valve
RESV = Reheat Emergency Stop Valve

CONTROL VALVES

Figure 2.3

For example, if an intercept valve would not operate, then the limiting of overspeed on a load rejection would be impaired as some steam would enter the LP turbine through the malfunctioning intercept valve. Under this condition, if continued unit operation was necessary the steam flow to the turbine might have to be reduced so that an overspeed would be limited to acceptable values. Similarly, if a reject valve were unable to open, the pressure in the piping from the HP to LP turbine might rise to unacceptable values on a load rejection. In this case the turbine might have to be derated to allow continued safe operation.

ASSIGNMENT

1. Define Station Heat Rate.

2. Define Turbine Heat Rate.

3. Why are station heat rate and turbine heat rate not equal?

4. What design factors can effect heat rate?

5. What operating factors can effect heat rate?

6. For your station how would you answer the question:

   "If half the feedheaters in a feedheating system were inoperative, why might it be necessary to derate the turbine?"

7. What factors might cause derating of a station?

R.O. Schuelke