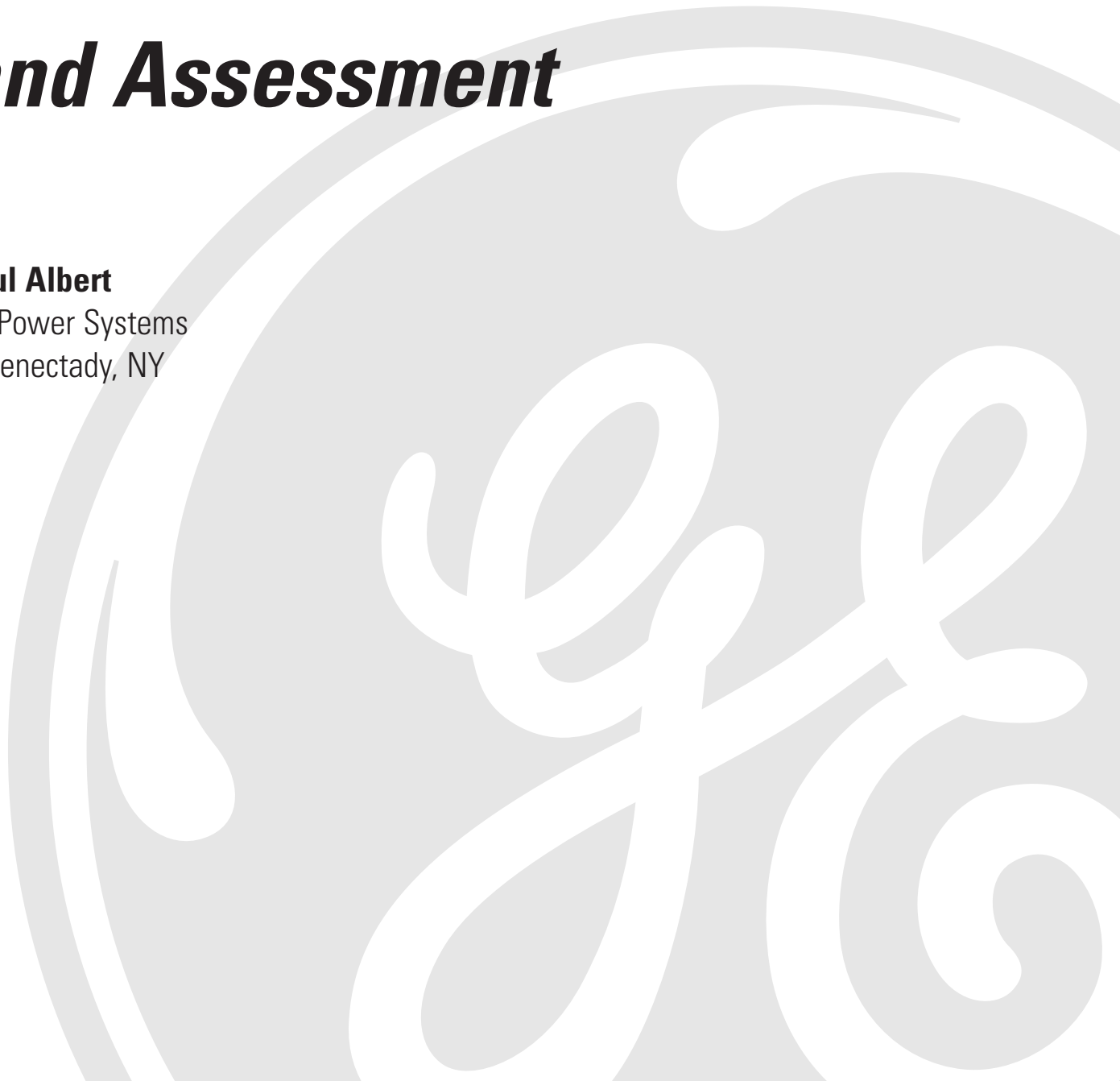




GE Power Systems

***Steam Turbine
Thermal Evaluation
and Assessment***

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Steam Turbine Thermal Evaluation and Assessment

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Steam Turbine Thermal Evaluation and Assessment

Introduction

For a steam turbine-generator to operate at its optimum level of thermal performance, it must achieve a high initial level of performance and must be able to sustain thermal performance over time. This is best achieved by an ongoing program of evaluation and assessment of thermal performance data. This program has a three-fold purpose. The first is to detect deterioration in the thermal performance by trending changes in various performance parameters. The second is to identify the cause of performance degradation by proper data evaluation and interpretation. The third is to develop cost-effective solutions to correct operational and equipment problems, which are contributing to the degradation in thermal performance. To meet these objectives, a thermal performance program should include the following essential factors:

- Obtain baseline performance data on individual turbines and cycle components during initial operation and after a maintenance outage to establish a base for identifying specific areas of performance losses
- Periodic acquisition of repeatable performance data
- Proper evaluation and assessment of performance data so that deterioration can be detected, located, trended, and corrected in a cost-effective manner
- Detailed inspection of and quantification of the expected performance recovery from restoration of turbine steam path

This paper identifies testing procedures and monitoring activities that are effective for obtaining and evaluating performance data.

This data, with its associated results, will establish accurate trends of various performance characteristics. The basic theory of the turbine steam path flow, pressure, and temperature relationships is reviewed to improve understanding of how these trends can be interpreted and used to locate and identify the cause of the turbine deterioration. Some common causes of turbine deterioration include deposits, solid particle erosion, increased clearances in packings and tip spill strips, and foreign object damage.

This paper also reviews the value of conducting a turbine steam path evaluation to identify the specific components contributing to the loss in thermal performance. In addition, this inspection can be used to verify the predictions of turbine conditions from the monitoring program. Technological advancements of GE's Performance Evaluation Services is also discussed.

Baseline and Periodic Performance Testing

A performance test conducted in accordance with the ANSI/ASME PTC 6-1996 "Steam Turbine" Code (*Reference 1*) is an accurate method of establishing the performance of a turbine-generator unit. The test requires the use of highly accurate calibrated instrumentation and highly controlled measurement procedures. When this code is used to conduct Acceptance tests, the uncertainty of the test result is very small. Although this code test provides excellent baseline performance, it generally is not economically justifiable for periodic testing as part of monitoring performance. However, the test code is useful in developing a basic understanding of the required measurements and procedures for determining the performance of a turbine-generator unit.

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The value of the analysis of performance test data greatly depends on the quality of the data. The use of “Acceptance” test procedures to obtain periodic performance results yields the most accurate test data for analysis and evaluation. Fortunately, performance monitoring does not necessarily require absolute accuracy, but it demands repeatable data for establishing accurate trends of various performance characteristics so simplified procedures can be used.

ASME PTC 6S Report

The ANSI/ASME PTC 6S Report “Simplified Procedures for Routine Performance Tests of Steam Turbines” (*Reference 2*) provides guidance in developing procedures to monitor performance. This procedure provides the necessary data to determine turbine cycle heat rate, kilowatt capacity, HP and IP section efficiencies, and turbine stage pressures and flow capacities.

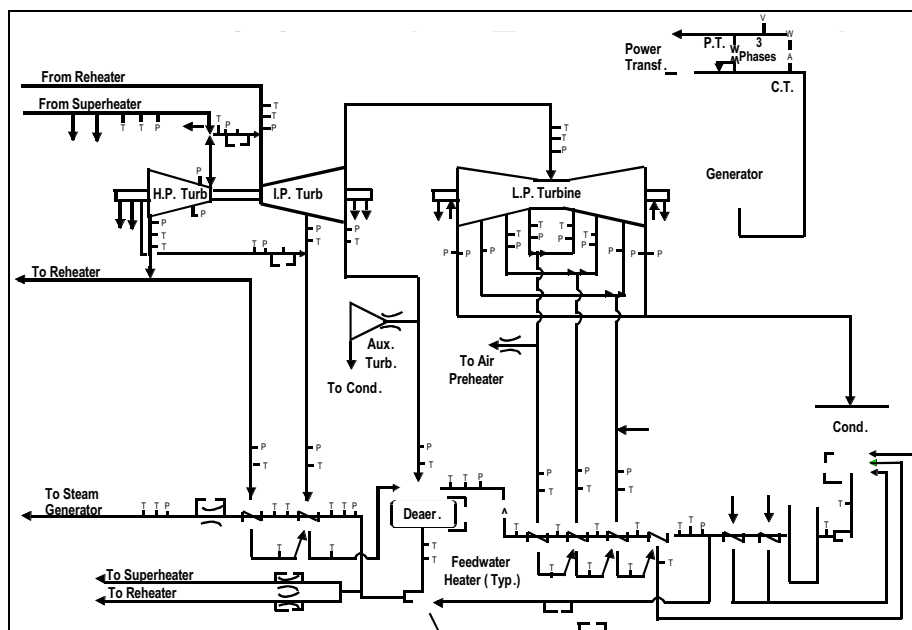
The essential measurements for ASME PTC 6S Report tests are shown in *Figure 1*. For this test, like other heat rate tests, the most important measurements are electrical load and primary flow, which is usually measured in the feedwater line. To assure repeatability, the differential

pressure transducer on the primary flow element should be calibrated prior to the test. In addition, mechanical station watt-hour meters usually have to be read by counting disk revolutions to obtain a precise reading of kilowatt output. Temperatures and pressures at the inlet and outlet of the HP and IP sections should be made with instruments capable of producing high repeatability.

The repeatable determination of the turbine cycle heat rate also depends on cycle isolation. Since primary flow is measured in the feedwater line, any leakage between the flow measurement and the turbine stop valve must be eliminated or the test results adjusted accordingly. Otherwise, an erroneous measurement of heat rate will be obtained. Steam and water leakages within the turbine cycle do not affect the measurement of heat rate, but these leakages can cause a significant loss in the actual heat rate and kilowatt capacity.

Capacity Test

When a repeatable measurement of primary flow cannot be obtained, another practical, effective method of trending the performance



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Figure 1. Test instrumentation location for a PTC 6S Test - fossil unit

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of the turbine-generator unit is to make periodic measurements with the turbine control valves wide open (VWO). This test, usually referred to as a Capacity Test, determines the generator output capacity, HP and IP enthalpy drop efficiency, and turbine stage pressures.

In rare cases, when steam generator capacity may be inadequate to drive the unit to a VWO position at rated pressure, one alternative is to reduce pressure to permit opening all inlet control valves. This procedure is preferred over the more demanding method of accurately reproducing positions of partially opened control valves or for correcting results for valve position.

The Capacity Test, like the simplified heat rate test, depends on repeatable measurements of electrical output and the pressures and temperatures at the inlet and outlet of the HP and IP turbine sections. Isolation of the turbine cycle is also important because it can significantly affect the electrical output of the unit.

Enthalpy Drop Test

The Enthalpy Drop Test is used frequently for monitoring steam turbines. This test involves a minimum number of instruments, but establishes the efficiency of those turbine sections most susceptible to deterioration. An Enthalpy Drop Test can be conducted on any turbine section operating entirely in the superheat region, such as the HP and IP sections of fossil reheat units and the HP section of automatic extraction units. The pressure and temperature ahead of and at the exhaust of the section being tested must be measured. The efficiency of the section can then be calculated from the ratio of actual to isentropic enthalpy drop. The turbine expansion line in *Figure 2* illustrates this relationship.

The measurements required to determine the HP and IP turbine section efficiencies are shown in *Figure 3*. Pressure taps and thermo-

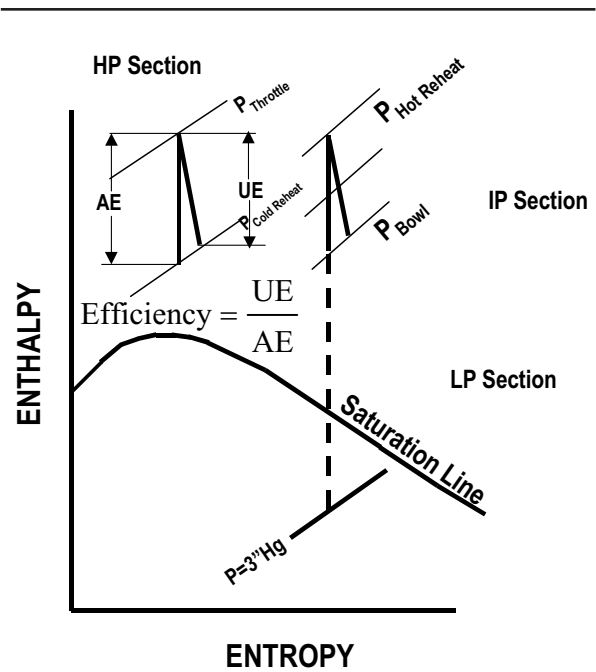


Figure 2. Enthalpy Drop Test

couple wells should be located ahead of the turbine stop valve, ahead of the intercept valve, in each cold reheat pipe, and in the crossover or low-pressure section bowl. In the cold reheat pipes, the pressure taps should be near the HP section exhaust connection, and the thermocouple wells should be in the horizontal pipe after the first elbow to ensure good mixing before measuring the temperature.

Duplicate temperature instrumentation should be used to conduct an Enthalpy Drop Test. This will not only improve the accuracy of the data, but will also detect a faulty temperature measurement. When there are two separate steam leads from the boiler to the turbine, duplicate instrumentation is recommended in each lead.

Evaluation of Performance Data

The effort of obtaining good repeatable test data will be lost unless that data is properly evaluated. The generator output and turbine cycle heat rate depends on the operating conditions of the turbine cycle and the performance of the

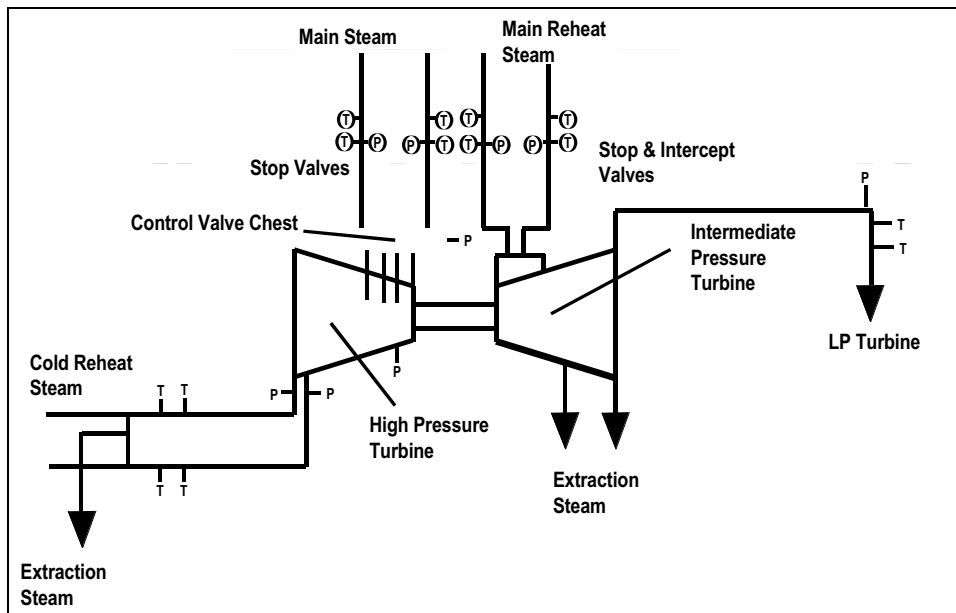


Figure 3. HP & IP efficiency measurement locations

many individual equipment components. If the test results indicate that heat rate has deteriorated or the maximum electrical capacity of the unit has changed, any of the following conditions could be contributing factors:

- Turbine steam flow
- Efficiency of the turbine steam path
- Available energy of the turbine (i.e., steam conditions)
- Performance and operation of the balance of plant components

To assess the turbine condition and its contribution to any deterioration in thermal performance, output and heat rate must be corrected for the influence of two non-turbine related factors: (1) the available energy of the turbine and (2) the performance and operation of the balance of plant components.

The available energy of the turbine is affected by variations in the following operating conditions:

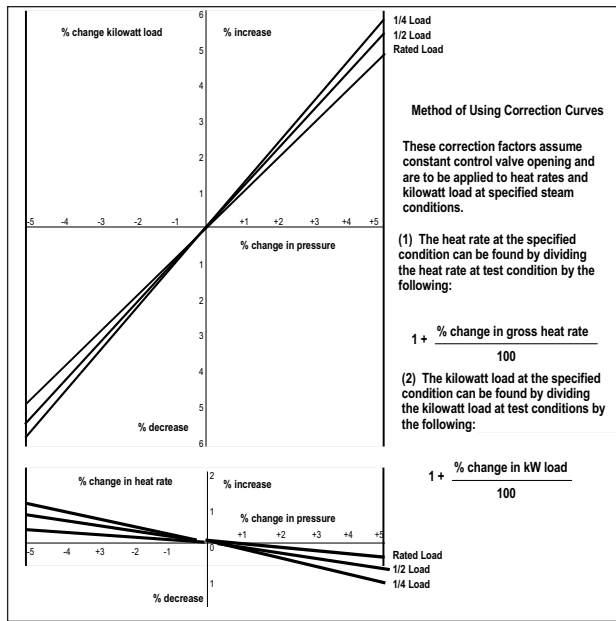
- Throttle pressure
- Throttle temperature

- Reheat temperature
- Reheater pressure drop
- Condenser vacuum

Heat rate and generator electrical output must be corrected for these operating conditions using correction factor curves normally provided in the unit's thermal kit. *Figure 4* is a sample of a correction curve. Variations in throttle pressure and temperature also change mass flow due to their effect on the specific volume of steam. This effect is typically combined with the available energy effect in the relevant correction factors. Keep in mind that these corrections also represent an accounting of performance losses due to operating conditions.

When assessing the turbine condition, it is necessary to account for variations in the performance and operation of balance of plant components, such as feedwater heaters and auxiliary process flows. Every effort should be made to eliminate or minimize flows which might vary due to seasonal changes or other causes. A thermal model program or valid correction curves can be used to correct for cycle or balance of plant changes.

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Figure 4. Throttle pressure correction for single reheat units

The generic correction curves from the ASME PTC 6S Report test code for the more significant cycle changes are listed below:

- Final feedwater temperature
- Auxiliary extractions
- Main steam attemperation
- Reheat steam attemperation
- Condensate sub-cooling
- Condenser make-up

A sample correction curve is presented in Figure 5.

Occasionally, it may be necessary to make corrections for out-of-service feedwater heaters or for cycle leakages. These effects can best be calculated by heat balance calculations, but often can be adequately estimated by simplified calculations which consider first order effects. A rigorous program should be in place to identify, quantify, and eliminate cycle leakages because they typically affect the thermal performance of the plant by more than one percent during normal operation.

Once these corrections have been made the

trend in heat rate and/or generator output can be used to assess the turbine condition. Steam flow and steam turbine efficiency are the two relevant factors which must now be considered. If the efficiencies of the superheated turbine

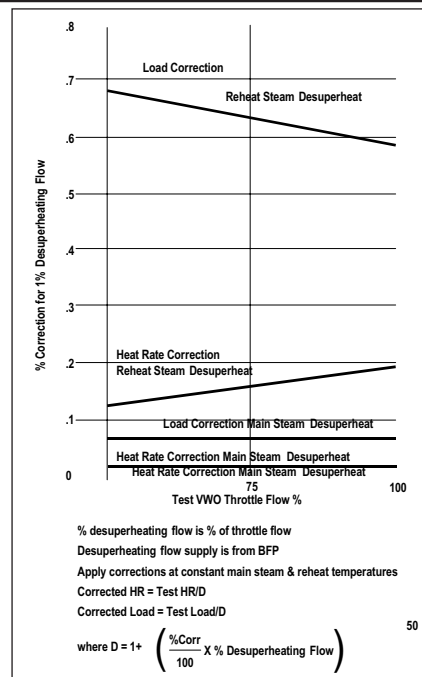


Figure 5. Correction for main steam and reheat steam desuperheating flow

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sections have been established, a change in efficiency can be expressed in terms of a change in heat rate and generator output. Some typical values for the percent change in heat rate for a one-percent change in section efficiencies for a single reheat unit are:

HP turbine	= 0.17
IP turbine	= 0.12 to 0.25
IP and LP turbine	= 0.72

For non-reheat and industrial turbines with more than one turbine section, the effect on overall performance due to a change in the efficiency of one section can be estimated by multiplying that change by the proportion of total unit power produced in that section.

The turbine efficiency characteristics must be understood in order to compare test results to design or to previous test results. For example, *Figure 6* illustrates the efficiency characteristics of an HP turbine section in a fossil unit application.

An HP turbine achieves its best efficiency with all control valves wide open (VWO) and, as the control valves are closed (or throttled), the efficiency decreases. The parameters usually used to represent valve position are a percent of valve

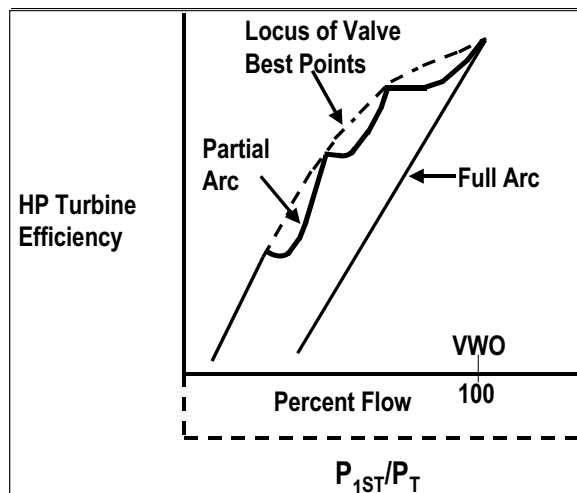


Figure 6. HP turbine efficiency

wide-open flow (at rated throttle pressure and temperature) or a pressure ratio, such as first stage pressure divided by throttle pressure. The upper curve represents a partial arc or partial-admission unit with the first stage nozzles divided into four separate nozzle arcs, each being supplied with steam from its own control valve. The lower curve represents full arc or single admission with all control valves connected into a common chamber ahead of the first stage nozzles. Both curves demonstrate the significant effect of valve position on HP efficiency and the need for testing at valve positions, which can be set repeatedly and held constant for the test.

Assessment of Turbine Conditions

The proper interpretation of test results can lead to an assessment of the internal condition of the turbine which can assist in prioritizing maintenance activities. There may be indications of mechanical damage in a turbine section, deposits or solid particle erosion. Knowledge of the turbine characteristics is necessary to understand why the performance has changed.

Maximum generator output is directly affected by changes in the efficiencies of the various turbine sections and changes in the flow capacity of the first three or four stages of the high-pressure turbine. Changes in the flow capacity of following stages may indicate a physical change in the steam path and consequential effects on local steam path efficiency. A change in the flow capacity of the turbine or the flow capacity of a particular turbine stage is reflected in the stage pressure, temperature, and flow relationship. Section 6 of the ASME PTC 6S Report contains a detailed discussion of these turbine characteristics. For all turbine stages except the first and last stage, the stage pressure ratios are essentially constant and the basic flow equation simplifies to:

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$$W = KAC_q \sqrt{P/v} \quad (1)$$

where:

- W = Flow to the following stage
- K = A constant
- A = Nozzle area
- C_q = Coefficient of discharge
- P = Inlet stage pressure
- v = Specific volume at stage inlet

The equation can be rearranged as:

$$W / \sqrt{P/v} = KAC_q \quad (2)$$

From the equation of state of an ideal gas (Pv = RT) the equation can be arranged as:

$$W / P \sqrt{1/R * T} = KAC_q \quad (3)$$

where:

- R = Universal gas constant
- T = Inlet stage temperature

This equation states that the flow function ($W / \sqrt{P/v}$) is related to the flow passage area of the stage (A) and the design and condition of the stage passage (C_q). In more general terms, the flow function relates to the steam path condition. If a particular stage flow function has changed, then the downstream condition of the turbine steam path must have changed. This is a powerful diagnostic tool in identifying damage, deposits, erosion or other problems which have affected a group of stages within the turbine steam path. If the effective flow area of a stage increases due to erosion or other problems, the flow function will also increase. Some problems, such as deposits, cause a reduction in the effective area of stage and a corresponding decrease in the flow function.

The flow function can be used to recognize that a change has occurred in the effective area of

the stage. However, the flow function is not proportional to the area change as implied in the equation. It is important to note that the derivation of the flow function equation is based on a constant pressure ratio across the stage. When the effective flow area of a stage changes, the stage pressure ratio also changes. Thus the relationship of the flow capacity to nozzle area is somewhat more complex. *Figure 7* shows the flow capacity change that can be expected for a change in nozzle area of an impulse-type turbine. For example, a 10% reduction in the nozzle area of the first stage would reduce the maximum capacity of the unit by about 3%.

Since the Capacity Test does not provide a repeatable measure of the primary steam flow, the flow function cannot be calculated. An option is to trend turbine stage pressures. As shown by *equation 1*, the steam flow divided by the absolute pressure ahead of a stage is proportional to the effective area of the following stage, provided that the temperature remains constant. For a constant valve position and constant inlet steam conditions, a change in a turbine stage pressure indicates either a change in the effective area downstream of the stage or a change in the flow capacity of the unit.

To use the trend of turbine stage pressures to predict the internal condition of the turbine, the stage pressures during the test must be corrected to reference steam conditions. The first stage pressure observed during a test on the HP section of a reheat turbine, or the pressure for any stage on a non-reheat turbine, should be corrected to reference conditions by the following equation:

$$P_c = P_o * P_d / P_t \quad (4)$$

where:

- P_c = Corrected pressure for plotting
- P_o = Measured stage or shell pressure

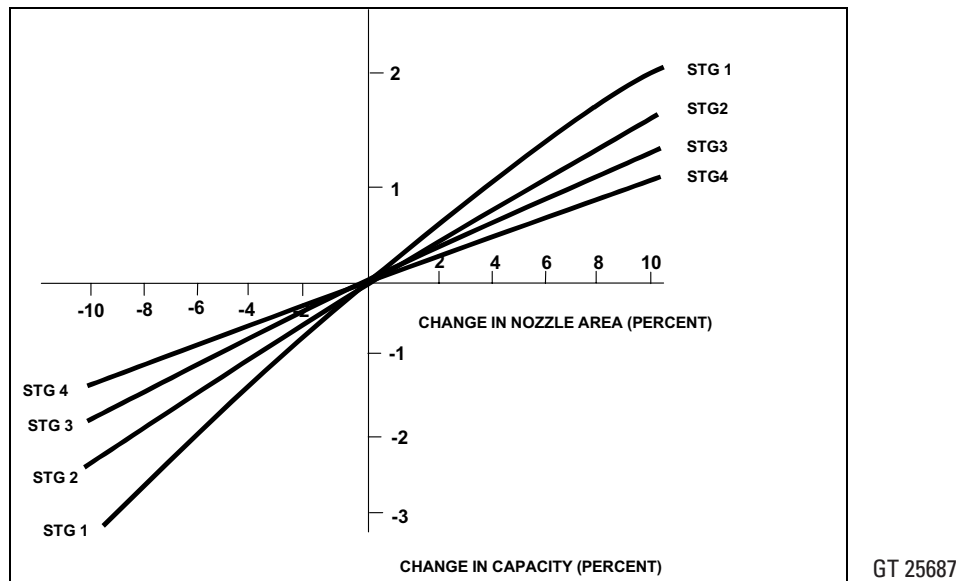


Figure 7. Effect of change in nozzle area on flow capacity for impulse-type turbines

P_t = Test throttle pressure

P_d = Design, or reference, throttle pressure

When an extraction for feedwater heating is taken from an intermediate stage in the HP turbine section, the measured stage or shell pressure should also be corrected using the same equation. Although not theoretically accurate, this correction is a very close approximation.

For stage or shell test pressures at or following the inlet to the reheat section of the turbine, and for the exit from the last stage of the HP section, additional corrections must be made for variations in throttle temperature, reheat temperature, and reheat spray flow to the boiler. The correction equation to be used is:

$$P_c = P_o * (\text{Throttle pressure and temperature correction}) * (\text{Reheat temp. correction}) * (\text{Reheat spray correction})$$

$$P_c = P_o * \sqrt{\frac{(P_d * v_t)}{(P_t * v_d)}} * \sqrt{\frac{v_{dr}}{v_{tr}}} * (1 - (W_{rhs}/W_{rhb})) \quad (5)$$

where:

v_d = Design, or reference throttle specific volume

v_t = Test throttle specific volume

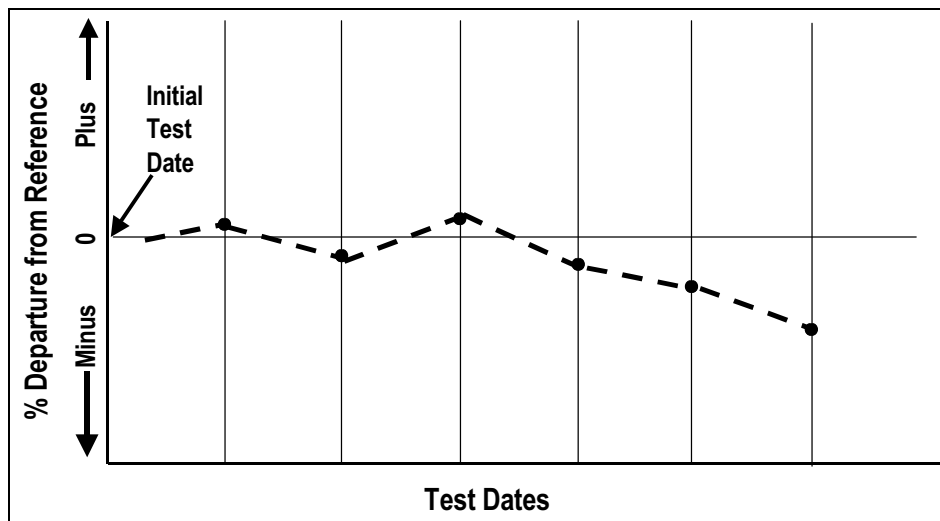
v_{tr} = Specific volume at test temperature and test pressure at inlet to intercept valves

v_{dr} = Specific volume at design reheat temperature and test pressure at inlet to intercept valves

W_{rhs} = Reheat spray flow to the boiler

W_{rhb} = Reheat bowl flow

Once the turbine stage pressures are standardized, the percent difference from a reference or design value should be calculated. Then the values can be plotted vs. chronological test dates as shown in *Figure 8*. The percent change in other performance parameters such as heat rate, generator output, section efficiencies, flow function, etc., can all be plotted on similar graphs.



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Figure 8. Pressure or capability curve vs. chronological test dates

Turbine Steam Path Evaluation

The interpretation of the results of performance monitoring activities can be used to identify turbine internal problems causing a deterioration in performance, and assist in planning maintenance required to address the problems. However, to restore performance during a turbine maintenance outage, the turbine components contributing to the performance loss need to be identified. This can best be done by conducting a turbine steam path evaluation.

A steam path evaluation should include a detailed visual inspection of the steam path components and clearance measurements of the packings; and tip spill strips. The visual inspection should evaluate and quantify the performance impact of degradation effects such as erosion, deposits, damage, peening, etc. Clearance measurements at multiple circumferential positions of the diaphragm packings, tip radial spill strips, and end shaft packings should be used to quantify the effect of increased clearances. With this information, decisions can be made based on the economics associated with the repair and replacement of turbine components, and the priority of necessary repair work.

The steam path evaluation should categorize the identified stage performance losses into six components: excess diaphragm packing leakage loss, excess radial tip spill strip leakage loss, nozzle recoverable and unrecoverable losses, and bucket recoverable and unrecoverable losses. Recoverable losses are defined as those that can be recovered by cleaning, dressing, repair of the components, or replacement of clearance controls. The unrecoverable loss is that part of the performance loss that can only be recovered by replacement with new components, such as new diaphragms or buckets.

Advanced Method for Assessing Stage Efficiency Losses

Most steam path audit thermodynamic evaluations performed in the past were based on consideration of steam path components and turbine sections as discrete entities. The complex interplay of the effect of observed losses on a given stage upon another stage was more difficult to discern. With the capability of a PC it is now possible to employ the capabilities of more sophisticated analysis programs that were, in the past, only available on a mainframe computer. Advanced methods being used consider

not only the effect of the observed component losses on the steam path efficiency, but also the interaction between these complex loss mechanisms. In other words, the feedback effect of the observed losses can now be calculated in greater detail and with greater accuracy.

GE has introduced a new tool for assessing the loss mechanisms that are evaluated during a Steam Path Audit. This new tool is called SPA 2000, and is a PC-based program that uses a stage-by-stage calculation to analyze the performance of a turbine section. This program, which is a user-friendly version of the same analysis program used by GE design engineers, is calibrated based on many years of field test data and GE lab test data. It is the most accurate tool available to the auditor for the prediction of turbine section performance and flow capacity. SPA 2000 is used for obtaining input of design data and inspection data, as well as for reporting stage and turbine performance output data. Additional input parameters have been added to allow the auditor to input specific component losses observed on the nozzle and bucket profiles.

SPA 2000 is a FORTRAN-based program that uses a closed system for making comprehensive performance calculations, including the following:

- Nozzle and bucket efficiency
- Flow passing capability
- Leakage flow calculations
- Rotation losses
- Carryover loss between stages
- Supercritical and wet expansions
- Partial arc stages
- Moisture loss
- Idle bucket loss
- Non-uniform discharge pressure
- Governing stage calculation

Loss Mechanisms

Stage efficiency losses may be caused by a number of reasons, such as deposits, solid particle erosion (SPE); foreign object damage (FOD), rubbed or damaged packings, or rubbed or damaged spill strips. Regardless of the causes leading to losses, stage efficiency losses may be quantified by sorting the losses into one of the following four categories:

- Leakage loss
- Friction loss
- Aerodynamic loss
- Loss caused by changes in flow passage areas

These losses prevent the efficient transfer of the energy into shaft work as the steam is expanded through a turbine stage.

Leakage Losses

In order for a turbine to produce shaft power, steam must pass through both the nozzle and bucket flow passages. Steam bypassing either the nozzles and/or buckets due to diaphragm interstage packing leakage, bucket root leakage or bucket tip radial spill strip leakage, will not produce kilowatts. It may also disrupt the flow through the nozzles and buckets in such a way as to further decrease turbine shaft output. Leakage losses are caused by increased clearances between the rotating and stationary components. These increased clearances are caused by rubbing between components, solid particle erosion or foreign object damage. The amount of the loss will be a function of the amount of the leakage flow. The amount of leakage flow is a function of the clearance (leakage) area, the geometry of the leakage path, and the pressure drop (pressure ratio) across the component that the leaking steam is bypassing. Equations can be used for the discrete calculation of leakage flow through an interstage diaphragm packing, or a tip or root spill strip. However, this

does not account for the effect of the increased leakage on the energy distribution on the stage or the consequence of it on the downstream stage. For example, if there is excess root clearance on a diaphragm spill strip, there will be an increase in the flow entering or leaving the steam path, which, in turn, affects the root reaction of the stage and the amount of flow which passes through the bucket dovetail hole or the wheel hole. Similarly, if additional leakage flow is calculated over the tip spill strip of a bucket, the tip reaction of the stage will also be affected, which affects the energy distribution on the stage as well as on the stage immediately downstream. The stage-by-stage analysis program utilized by SPA 2000 calculates the various leakage flows in the steam path based on all of the measured clearances during the audit. Furthermore, the complex interplay of the increase or decrease in any of these flows relative to the design case for each stage is determined.

Friction Losses

Stage efficiency losses due to an increase in the measurable roughness of a nozzle partition or bucket vane surface will be a function of the ratio of the height of the projections to the thickness of the boundary layer, and whether this flow is laminar or turbulent (Reynolds Number). The thinner the boundary layer (higher Reynolds Number), the more significant the friction loss becomes, even for small projections. Projections are caused by contaminants in the steam which deposit on the surface of the partitions. Projections are also caused when foreign particles collide against partition surfaces, leaving behind small indentations in these surfaces. Quantifying friction losses in steam turbine airfoils is a complex topic, which is further explained in *Reference 3*. Many factors contribute to the amount of this loss. Such factors include the location (suction vs. pressure

side), the orientation, the size, and the geometry of the projections on the airfoil surface. It is customary when evaluating friction losses to divide the airfoil into three regions: leading edge, suction side trailing edge, and pressure side trailing edge. Nozzle suction side roughness affects stage efficiency approximately three times more than pressure side roughness. The leading edge roughness will have the greatest contribution to stage efficiency loss occurring on the bucket. Bucket leading edge suction side roughness affects stage efficiency approximately two times more than pressure side roughness. Also, because of the higher-pressure drop through the nozzles relative to the buckets on an impulse design stage, approximately 75% of a stage efficiency loss caused by surface roughness is attributed to the nozzles. *Figure 9* shows the approximate loss in stage efficiency as a function of surface finish for GE steam turbines. This information is separated by turbine section. Since higher Reynolds Numbers are found in the High-Pressure section (smaller boundary layer), the smaller the projections have to be in order to avoid an increase in friction loss. This plot assumes a 63 micro-inch finish for the as-built surface finish of the partitions. Common causes for friction losses include deposits and foreign object damage. Although the Steam Path Audit inspection requires an evaluation of the surface roughness on each of the turbine components, as well as the location of particular grades of roughness, the SPA 2000 program only requires the auditor to assess the roughness on the particular component, and not to evaluate the roughness on a stage based on an assumed level of reaction for the stage. Because other loss mechanisms may affect the stage reaction and the energy distribution on the stage, the effect of increased roughness on a component may have a more or less severe effect on the stage efficiency than if

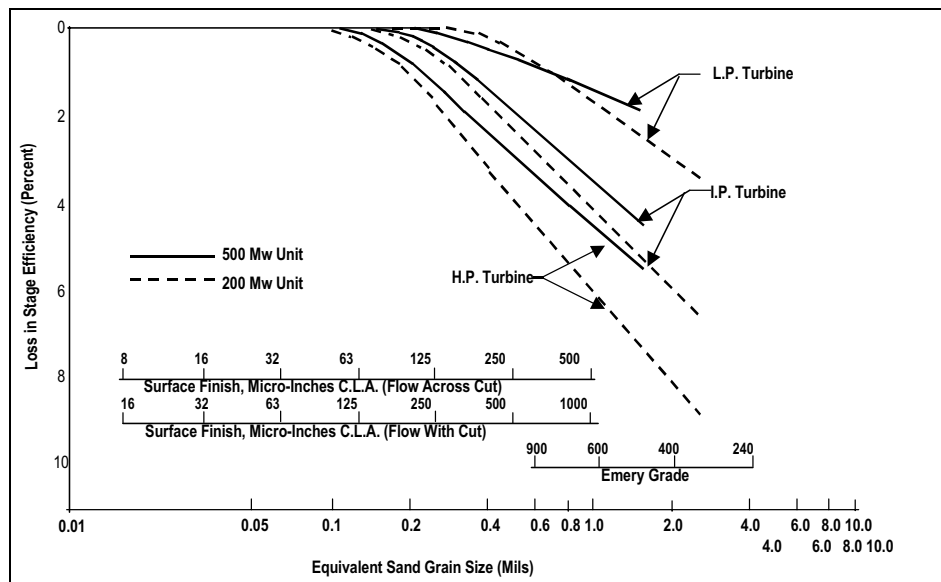


Figure 9. Approximate loss in stage efficiency as a function of surface roughness

the roughness is applied as discrete loss in stage efficiency relative to the stage in a new and clean condition with all other geometrical parameters equivalent to their design values.

Aerodynamic Losses

As previously mentioned, turbine nozzle and bucket profiles and geometry are designed so that steam accelerating through nozzle passages can be redirected onto the buckets at optimum entrance angles and velocities. Any changes to nozzle and/or bucket profiles will change the entrance and/or exit steam angles, increasing the aerodynamic losses within a stage. These factors are critical considerations when repairs are made to these components.

Three critical parameters which should be routinely inspected during the Steam Path Audit to quantify these “off-angle” steam losses include nozzle trailing edge thickness, nozzle throat widths, and bucket leading edge profiles. *Figure 10* shows a plot of stage efficiency loss as a function of trailing edge thickness for different nozzle

throat widths. HP and IP turbine section diaphragms are designed with nozzle trailing edge thickness in the range of 15 to 25 mils, depending on the stage. The most common causes of off-angle losses are due to erosion of nozzle trailing edges and poor quality repairs. When nozzle trailing edges become eroded, the nozzle trailing edges decrease until, when enough material is lost, pieces of trailing edges begin to break off. When this occurs the trailing edge thickness will increase and the off-angle losses will increase. Diaphragm repairs which increase nozzle trailing edge thickness above the design thickness will also increase the amount of off-angle losses. The SPA 2000 program uses the loss curves presented in *Figure 10*, but it is only necessary for the auditor to input the design and measured trailing edge thickness for each diaphragm and the program will automatically calculate the loss (or gain) in efficiency on the turbine stage, and its associated affect on the inlet conditions to the downstream stage.

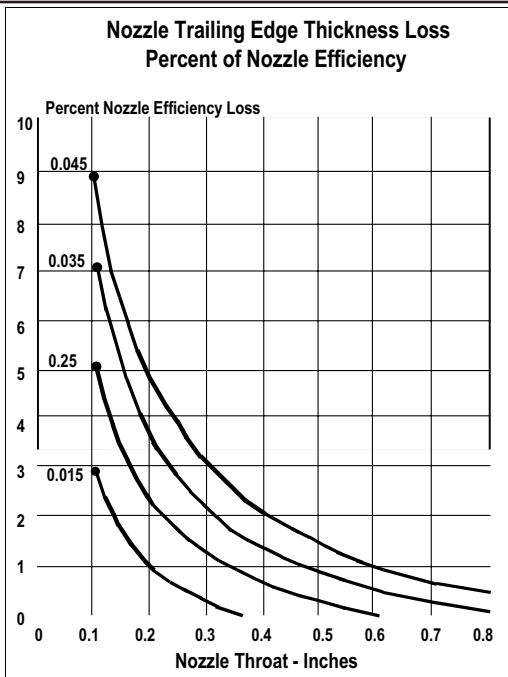


Figure 10. Estimated loss in stage efficiency for different trailing edge thickness

Losses Due to Changes in Flow Passage Areas

If the flow passage area of a stage changes, the initial pressure into that stage must change in order to pass a constant steam flow. This change in the initial pressure will change the amount of available energy to the stage, which in turn will affect the efficiency of the stage. Changes to flow passage areas are commonly caused by deposits (area reduction), erosion (area increase), or mechanical damage (area reduction or increase). An approximate rule of thumb for an impulse-type stage is a 10% increase in nozzle throat area will result in a 3% stage efficiency loss for a stage other than a control stage.

In addition to the effects on stage efficiency, changes in stage areas will also affect the flow passing capability of the turbine. This will in turn have an additional effect on the kilowatt generating capability of the turbine for a con-

stant valve position. Deposits in the nozzle throat area will decrease the efficiency as well as the flow passing capability (and therefore kilowatt capability) of the unit, while erosion of nozzle flow passages will decrease the efficiency but increase the turbine's flow passing capability.

However, with the introduction of the SPA 2000 program, the geometry specific to the steam path is used to calculate the flow passage through the turbine stages and a more accurate prediction of the flow capacity of the unit can be determined. This analysis also includes the effect of the change in the stage flow coefficients due to the presence of the observed loss mechanisms, such as steam path erosion or deposits on the turbine stages.

SPE damage to the turbine steam path can also result in secondary cycle losses caused by changes in section efficiencies and stage pressures. For example, higher-than-design cold reheat temperatures (caused by erosion in the HP section) may necessitate the need for reheat attemperation. First reheat stage erosion will reduce cold reheat pressure, resulting in a lower pressure to the final feedwater heater and thus a reduced final feedwater temperature when the turbine extraction to the top heater is at the reheat point. First reheat stage erosion will also reduce the reheat bowl pressure, thus increasing the velocity through the reheater and the reheater pressure drop.

Steam Path Audit Reporting

Immediately following the conclusion of the steam path audit, a preliminary report is prepared which contains the thermodynamic and structural evaluations of the audit so that the findings and recommendations can be incorporated and implemented in a timely fashion during the outage period. The performance or thermodynamic evaluation portion of a Steam

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Path Audit report, using SPA 2000, will include the following information:

- Background information on unit inspected
- Efficiency appraisal evaluation summary
- Tabular breakdown of losses
 1. End shaft packings and snout rings.
 2. Recoverable losses for each section showing losses by component (on each stage inspected).
 3. Unrecoverable losses for each section showing losses by component (on each stage inspected). (See Figure 11.)
- Graphical presentation of results
 1. Recovered losses for each turbine section inspected (pie charts).
 2. Summary of losses by stage and type (bar charts).
 3. Summary of losses by stage for each major component, i.e., bucket, nozzle, tip leakage, root leakage (bar charts).

■ Color photographs of steam path

Photos of the major components and each stage which is inspected are made using either traditional photography or employing the latest in digital camera technology. Digital photography (see Figure 12) allows the auditor to make a quick review of the quality of the photographs. This format makes the photos easily available via e-mail to GE turbine experts who are not present at the site. This enhances the comprehensive analysis that is presented to the customer in a report-out at the conclusion of the audit.

Advancements in the Evaluation and Assessment of Data

The prior section explained the value of an Advanced Steam Path Audit (SPA 2000) during a steam turbine maintenance outage. Advancements are also ongoing for acquiring, evaluating, and assessing thermal performance of operating power plants. To deliver more customer value, the focus of advancement is on automation, remote access for timely diagnostic assistance, and expansion of expertise to cover the entire power plant.

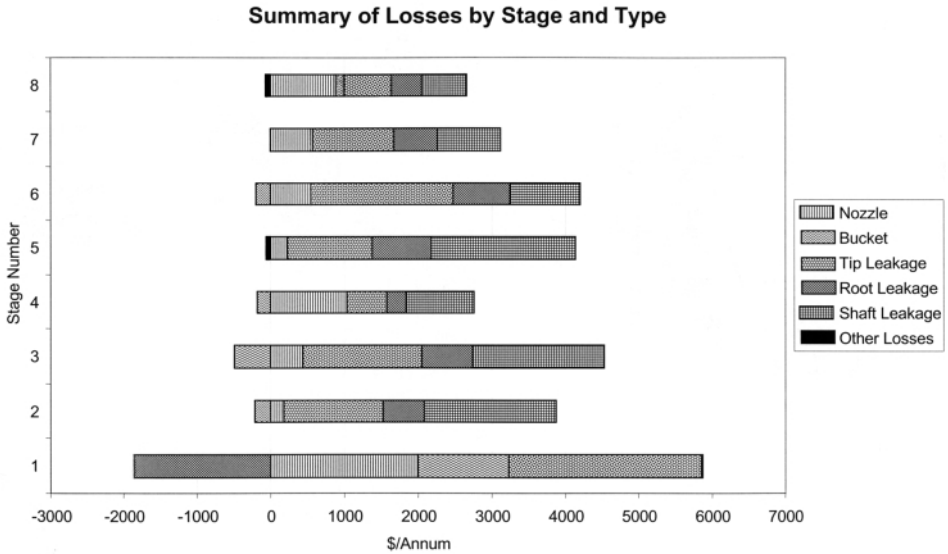


Figure 11. Overall summary of losses



Figure 12. Digital photography

Performance Monitoring

Performance Monitoring is an ongoing diagnostic activity coupled with software tools that allow the collection and presentation of data. Preliminary interpretation of the data can be performed automatically. A detailed review and determination of data requires periodic review by an engineer and/or plant operator. GE now offers performance monitoring products for steam turbines / gas turbines / combined cycle plants which have a suite of related modules that provide on-line plant performance monitoring. The performance monitor powered by GE Enter Software's EfficiencyMap and Gate Cycle software provide real-time guidance to plant owners and operators with four modules.

The **On-line Heat Balance Module** validates and reconciles measured data from the plant to allow operators to conserve mass and energy around each of the major components.

The **Performance Module** calculates plant and component efficiencies, and resulting equipment degradation.

The **Optimizer Module** recommends the optimum plant equipment configuration to maxi-

mize overall plant profitability at any given time and operating conditions. The On-Line Optimizer uses real time data, allowing operators to determine how best to adjust controllable parameters to maximize profit. The Off-Line Module simulates the plant performance based upon specific user inputs to the heat balance model.

The **Data Module** consists of an embedded Plant Information (PI™) System by OSI Software, Inc., which communicates measured tag values from the plant DCS and serves as EfficiencyMaps' historian.

Plant diagnostic assistance, remote software support and consulting services are provided upon request by experienced GE Enter Software engineers and experienced GE thermal performance engineers. With the customer's permission, data and results can easily be communicated to GE's Monitoring and Diagnostic center in Atlanta, GA.

Plant Evaluations

GE is now positioned to leverage EER's* fossil boiler thermal and emission expertise along with GE's steam turbine cycle thermal perform-

ance expertise to deliver a Total Plant Evaluation Service. This service enables the customer to make cost-effective business decisions to improve plant efficiency or increase plant electrical output capacity. This service begins by gathering plant design data to understand the expected performance and operating constraints of a plant. Next, performance engineers visit the plant to gather performance data and to gain a first-hand understanding of the operating requirements and limitations. A detailed assessment is completed to identify loss performance and recommend about operational changes or maintenance actions to recover performance. The study can also include a thermal model study of equipment uprates/upgrades or cycle modifications for improving plant efficiency or kilowatt capacity.

* EER Energy and Environmental Research Corporation, a wholly owned subsidiary of General Electric Company

Summary

Over the next few years, becoming the “low-cost” power producer will be increasingly important. Power plant owners can make a significant contribution toward achieving this goal by implementing a well-organized performance-diagnostic program, which will reduce fuel costs and facilitate cost-effective maintenance.

This paper has presented some of the latest advancements used for evaluating and assessing the performance of your steam turbine, includ-

ing methods for periodic data acquisition, interpretation of performance data, inspection of the turbine steam path, monitoring the performance of your steam turbine and evaluating the total plant. These programs are essential in order to achieve and maintain the highest level of thermal performance of a turbine-generator unit.

GE continues to look for better ways to service customers by improving the thermal efficiency and kilowatt capacity of power plants. Today’s internet and e-Business technology is under development to better compare unit performance with fleet data and quickly assess pertinent information.

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Acknowledgements

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