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A Practical Approach to Comprehensive Performance Evaluation, Heat Rate Gap Diagnostics and Ai-Based Real-Time Optimization of Coal-Fired Power Plants

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ABSTRACT

Accurate measurement of boiler efficiency, turbine heat rate (THR), gross heat rate (GHR) and heat rate deviations are fundamental to assessing the true performance of a coal-fired generating unit during Performance Guarantee (PG) test and routine O&M phase. Small errors in coal flow, coal calorific value, steam flow, enthalpy, generator output, flue-gas measurements and correction factors can produce significant errors in calculated heat rate. This paper presents a practical methodology based primarily on ASME Performance Test Codes (PTCs), with emphasis on PTC 4 for fuel fired steam generators, PTC 6 for steam turbines, PTC 46 for overall plant performance and PTC 19.1 for test uncertainty. This paper emphasizes direct and indirect measurement methods, OEM correction curves, heat-rate gap analysis, repeatability, uncertainty, test preparation, coal sampling, practical do's and don'ts and application of AI.

Keywords - boiler; boiler efficiency; turbine heat rate (THR); gross heat rate (GHR); ASME PTC 4; PTC 6; PTC 6S; PTC 46; PTC 19.1; correction curves; uncertainty; repeatability; heat-rate gap analysis.

1. INTRODUCTION

The performance of a coal-fired generating unit is normally expressed through several linked indicators: boiler efficiency, turbine heat rate, gross heat rate, auxiliary power consumption and net heat rate. These parameters are interconnected but represent different physical boundaries. Boiler efficiency describes the effectiveness of the steam generator in transferring fuel energy to the defined useful output streams, whereas turbine heat rate relates the thermal energy supplied to the turbine cycle to electrical output. Gross heat rate (GHR) is fuel heat input per unit of gross electricity generated and Net heat rate (NHR) is fuel heat input per unit of net electricity exported after deducting auxiliary power consumption (APC).

2. APPLICABLE PERFORMANCE TEST CODES

2.1 ASME PTC codes intended for power plant

ASME PTC	Title / application	Relevance
PTC 4	Fired Steam Generators	Boiler efficiency and performance testing
PTC 6S	Steam Turbines	Routine performance testing of steam turbines with DCS instruments
PTC 6	Steam Turbines	Turbine heat rate and output with PG test instruments
PTC 46	Overall Plant Performance	Overall gross/net heat rate and plant performance
PTC 19.1	Test Uncertainty	Measurement uncertainty and test-result confidence
PTC 4.2	Coal Pulverizers	Mill performance
PTC 4.3	Air Heaters	Air-heater performance
PTC 12.2	Steam Surface Condensers	Condenser performance
PTC 12.1	Closed Feedwater Heaters	Feedwater-heater performance
PTC 12.3	Deaerators	Deaerator performance
PTC 8.2	Centrifugal Pumps	Boiler feed pumps and other centrifugal pumps
PTC 11	Fans	FD, ID and PA fan performance

2.2 ASME PTC 4 – Fired Steam Generators

ASME PTC 4 provides rules and instructions for performance testing of fuel-fired steam generators, including coal-fired units. For a pulverized-coal boiler, it is the principal reference for boiler performance testing. Important measurements include fuel flow and fuel properties, steam and water flows, steam pressure and temperature, flue-gas composition and temperature, air and gas flows, ash properties and applicable energy credits or losses.

PTC 4 provides both an Input-Output Method and Indirect Method. The two methods have different measurement requirements and uncertainty characteristics. In particular, fuel-flow measurement uncertainty can have a direct and significant influence on an Input-Output result. Tests should be conducted with as close as design gross calorific coal.

2.3 ASME PTC 6 / 6S – Steam Turbines

PTC 6 is used for formal steam-turbine performance testing, primarily for acceptance and guarantee verification. The turbine heat balance requires accurate measurement of condensate flow, main steam flow and conditions, reheat conditions, extraction flows, feedwater conditions, condenser pressure and generator output. Tests should be conducted as close as practicable to specified conditions so that correction requirements are minimized.

PTC 6S is simplified procedures for routine and periodic performance testing to monitor changes in turbine performance over its operating life using DCS instruments.

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2.4 ASME PTC 46 – Overall Plant Performance

PTC 46 establishes an overall plant-performance framework. It addresses determination of heat input and electrical or secondary outputs using direct or indirect measurements and provides for correction of measured performance to specified reference conditions. PTC 46 should not be treated as a replacement for PTC 4 or PTC 6 when testing individual components.

2.5 ASME PTC 19.1 – Test Uncertainty

PTC 19.1 provides the framework for identifying measurement uncertainties and propagating them into calculated performance results. A defensible report should therefore state both the measured result and the associated test uncertainty rather than reporting an apparently precise single number.

3. BOILER EFFICIENCY

3.1 Boiler Efficiency and Calculation Methodologies

Boiler efficiency represents the proportion of fuel energy transferred to the useful output streams within a defined steam-generator boundary. For a boiler, even a small change in efficiency can significantly affect the unit's gross heat rate and fuel consumption.

Two principal methodologies are used for calculating Boiler Efficiency:

- Direct or input-output method: Calculates efficiency from useful heat output and fuel heat input.
- Indirect or heat-loss method: Calculates efficiency by quantifying individual heat losses and subtracting their total from 100%.

The choice of method depends on the test objective, instrumentation quality, measurement uncertainty and required diagnostic detail.

This paper compares the principles, measurement requirements, advantages and limitations of both approaches. Particular emphasis is placed on the diagnostic capability of the indirect method for detailed loss analysis and performance improvement, while following the applicable ASME PTC 4 methodology for formal performance testing.

3.2 Direct Method (Input-Output Method)

The direct method calculates boiler efficiency as the ratio of useful heat transferred to the working fluid to the heat supplied by the fuel.

Boiler Efficiency, $\eta_B = \frac{Q_{\text{useful}}}{\dot{m}_f \times GCV} \times 100$

For a simplified steam-generation boundary:

$$Q_{\text{useful}} = \dot{m}_{ms}(h_{ms} - h_{fw}) + \dot{m}_{rh}(h_{hrh} - h_{crh})$$

where:

- $\dot{m}_f$= fuel mass flow rate
- GCV = gross calorific value of fuel
- $\dot{m}_s$= main steam mass flow rate
- $\dot{m}_{rh}$= hot reheat steam mass flow rate
- h_{ms}= main steam enthalpy
- h_{fw}= feedwater enthalpy
- h_{hrh}= hot reheat steam enthalpy
- h_{crh}= cold reheat steam enthalpy

For a boiler, the actual calculation or formulae must account for the agreed boundary, main steam spray-water flows, reheat spray-water flows, with or without reheater heat absorption wherever applicable, other relevant energy streams and the prescribed PTC calculation procedure.

Advantages

1. Simple to understand and implement.
2. Provides a direct relationship between fuel input and useful output.
3. Useful for routine monitoring and independent performance verification.

Limitations

1. Accuracy is highly dependent on fuel-flow measurement.
2. Coal GCV variability and non-representative sampling can introduce significant errors.
3. Steam/feedwater flow measurement errors directly affect the calculated efficiency.
4. Does not independently identify the individual causes of efficiency degradation.

3.3 Indirect Method (Heat-Loss Method)

The indirect method determines boiler efficiency by quantifying individual heat losses as percentages of fuel heat input.

$$\eta_b = 100 - \sum L_i + \sum C_j$$

Where:

- η_b = boiler efficiency, %
- L_i represents each applicable heat loss in percentage points.
- C_j= applicable heat credits (Credits account for additional heat entering the boiler system beyond the fuel's reference calorific value like sensible heat in air entering above the reference temperature, coal pulverizer and fan power)

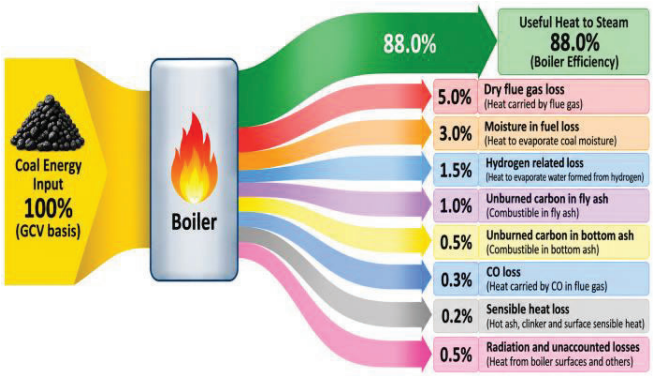
Major Boiler losses include:

Boiler Heat loss	Principal cause
Dry flue-gas loss	High exit-gas temperature and excessive flue-gas flow
Moisture in fuel	Evaporation of fuel moisture
Hydrogen-related moisture loss	Water formed during hydrogen combustion
Unburned carbon in fly ash and bottom ash	Incomplete combustion
CO loss	Incomplete conversion of carbon to CO_2
Radiation and convection	Heat rejected from boiler surfaces
Other applicable losses	Additional losses defined by the test methodology

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Typical Boiler losses and their proportions are,



a. Dry flue-gas loss:

The dry combustion gases leave the boiler carrying sensible heat.

$$L_{DG} = \frac{\dot{m}_{fg} c_p (T_g - T_r)}{\dot{m}_f GCV_f} \times 100$$

where $\dot{m}_{fg}$ is dry flue-gas flow, C_p is average specific heat, T_g is flue-gas temperature, T_r is the reference air temperature, $\dot{m}_f$ *is* as-fired fuel mass flow rate and GCV_f is gross calorific value of fuel.

b. Loss due to Water formation from hydrogen in the fuel:

Hydrogen in coal reacts with oxygen and forms water vapour. The resulting water vapour carries energy out with the flue gas.

$$L_{H_2} = \frac{\dot{m}_{H_2O,H_2}[h_v(T_g) - h_l(T_r)]}{\dot{m}_f GCV_f} \times 100$$

For fuel hydrogen mass fraction H,

$$\dot{m}_{H_2O,H_2} = 9H\dot{m}_f$$

where $\dot{m}_{H_2O,H_2}$ is mass of water vapor formed due to Hydrogen in fuel, $h_v(T_g)$ is the water-vapour enthalpy and $h_l(T_r)$ is the reference liquid-water enthalpy.

For example, at a flue-gas temperature of 140°C, the specific enthalpy of water vapour is approximately 2,764 kJ/kg, whereas the reference liquid-water enthalpy at 32°C is approximately 134 kJ/kg. Therefore, the heat carried away per kg of water vapour formed is approximately 2,630 kJ/kg.

c. Loss due to moisture present in the coal,

Moisture entering with the as-fired coal is heated, evaporated and superheated before leaving with the flue gas.

$$L_{M,f} = \frac{\dot{m}_{M,f}[h_v(T_g) - h_l(T_r)]}{\dot{m}_f GCV_f} \times 100$$

Where $\dot{m}_{M,f}$ is the moisture mass flow entering with the fuel.

If M is the as-fired fuel moisture mass fraction,

$$\dot{m}_{M,f} = M\dot{m}_f$$

d. Loss due to Moisture in combustion air,

Water vapour entering with the combustion air is heated and discharged with the flue gas.

$$L_{M,a} = \frac{\dot{m}_{H_2O,a}[h_v(T_g) - h_v(T_a)]}{\dot{m}_f GCV_f} \times 100$$

Where $\dot{m}_{H_2O,a}$ is the water-vapour flow entering with combustion air, T_a is inlet combustion-air temperature

e. Loss due to Unburned carbon in fly ash and bottom ash,

Carbon remaining in ash represents chemical energy that was not released by complete combustion.

$$L_{C,FA} = \frac{\dot{m}_{FA}\, x_{C,ash}\, H_{C,FA}}{\dot{m}_f GCV_f} \times 100$$

$$L_{C,BA} = \frac{\dot{m}_{BA}\, x_{C,ash}\, H_{C,BA}}{\dot{m}_f GCV_f} \times 100$$

Total unburnt carbon loss, $L_{C,ash} = L_{C,FA} + L_{C,BA}$

Where $\dot{m}_{FA}$, $\dot{m}_{BA}$ are fly ash and bottom ash-residue mass flow rate respectively, $x_{C,ash}$ is unburned-carbon mass fraction in the residue and $H_{C,FA}, H_{C,FA}$ *are* applicable heat value assigned to the unburned carbon in fly ash and bottom ash respectively

f. Loss due to Carbon monoxide (CO) in flue gas,

CO indicates incomplete conversion of fuel's carbon to carbon dioxide.

$$L_{CO} = \frac{\dot{m}_{CO}\, \Delta h_{CO}}{\dot{m}_f GCV_f} \times 100$$

Where $\dot{m}_{CO}$ is CO mass flow in the flue gas and Δh_{CO} is chemical energy released per unit mass of CO on oxidation to CO_2, using a consistent reference basis

g. Loss due to Sensible heat in ash and other residues

Hot fly ash, bottom ash, economizer ash or other applicable solid residues may carry sensible heat out of the system.

$$L_{ash,s} = \frac{\sum_j \dot{m}_j\, c_{p,j}(T_j - T_r)}{\dot{m}_f GCV_f} \times 100$$

Where j represents each applicable residue stream like fly ash, bottom ash and economizer ash

These expressions illustrate the physical basis of the loss. A formal PTC 4 calculation must use the applicable code-defined equations, fuel analysis, reference conditions and energy balance.

Advantages

1. Identifies the major contributors to boiler heat loss.
2. Supports root-cause analysis and targeted corrective actions.
3. Helps quantify the potential benefit of combustion tuning, air-heater improvement, coal-fineness optimization and reduction of unburned carbon.
4. Allows operating parameters to be correlated with individual losses.
5. Provides a useful foundation for boiler heat-rate gap analysis.

Limitations

1. Requires more measurements, sampling and laboratory analysis.
2. Accuracy depends on representative fuel and ash samples and reliable flue-gas measurements.

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3. Errors in several loss calculations may accumulate.
4. Some losses may be estimated rather than measured directly.
5. The result depends on consistent definitions, boundaries and treatment of unaccounted losses.

3.4 Comparative Assessment

Criterion	Direct method	Indirect method
Calculation principle	Useful output / fuel input	100% minus total losses
Instrumentation	Primarily fuel and steam/water-side measurements	Fuel analysis, gas analysis, temp, ash and other loss measurements
Calculation complexity	Relatively low	Relatively high
Sensitivity to coal-flow accuracy	High	Depends on the selected loss calculations
Loss identification	Limited	Detailed
Root-cause analysis	Limited	Strong
Routine monitoring	Useful	Useful when reliable datas are available
Performance optimization	Requires additional diagnostic data	Particularly suitable
Formal acceptance testing	Applicable when specified by the governing procedure	Applicable when specified by the governing procedure

From the comparative assessment, the Indirect Method Often Preferred for Boiler Performance Improvement. The principal reason is its diagnostic capability, rather than an unconditional guarantee of better numerical accuracy.

The direct method may indicate that boiler efficiency is 88.5%, but it does not independently explain why the remaining fuel energy was not transferred to useful output.

The resulting improvement cycle is:

Measure losses → Identify dominant loss →
Determine root cause → Implement corrective action →
Verify improvement

The indirect method is therefore especially valuable for performance-monitoring departments, boiler optimization and heat-rate gap analysis in day to day operation.

However, the indirect method is not automatically more accurate in every application. Its uncertainty depends on the quality of all the measurements used in the loss calculations.

3.5 Coal Analysis

Accurate coal sampling and analysis are essential for determining the true boiler efficiency of a thermal power plant. Since fuel heat input is the denominator in boiler efficiency calculations, any error in coal flow measurement or Gross Calorific Value (GCV) directly affects the calculated efficiency.

The main principle is: **a representative sample is more important than a large sample collected incorrectly.** ASME PTC 4 covers fired steam-generator performance testing, including coal-fired boilers, but it does not prescribe all procedures for determining the chemical and physical properties of fuel.

Best practices for reliable results

1. Collect representative increments across the coal stream and test period (usually 4 hrs during PG test and 2~4 hrs during O&M phase)
2. Prevent moisture loss, contamination and segregation during sampling and preparation.
3. Determine GCV using a calibrated bomb calorimeter and the applicable test method, such as ASTM D5865/D5865M.
4. Report GCV on the correct basis—as-received, as-fired or dry basis—and maintain consistency with the coal-flow measurement.
5. Follow the applicable ASME PTC 4 performance-test procedure and document measurement uncertainty.

Supporting sampling and analysis standards

These are ASTM/ISO standards, not ASME PTC codes:

- ASTM D2234/D2234M - collection of gross coal samples.
- ASTM D7430/D7430M - mechanical sampling of coal.
- ASTM D2013/D2013M - preparation of coal samples for analysis.
- ASTM D6609/D6609M - part-stream sampling guidance; recognize its limitations when representative full-stream sampling is required.
- ASTM D5865/D5865M – Standard Test Method for Gross Calorific Value of Coal and Coke
- ISO 13909 series - mechanical sampling, sample preparation and precision/bias assessment for coal and coke.

Best practices during the GCV test:



Sample Weighment



Bomb Calorimeter

- Weigh the coal sample accurately using a calibrated analytical balance. Use the integrated weigh balance with bomb calorimeter to avoid manual typo errors.
- Ensure the sample is representative and properly homogenised.
- Use a clean, dry crucible and avoid sample contamination.

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- Ensure the sample is positioned appropriately for reliable combustion.
- Follow the instrument manufacturer's approved procedure for oxygen charging and ignition.
- Ensure complete combustion; inspect the residue after the test.
- Apply the prescribed corrections for ignition wire, fuse wire, acid formation and other applicable contributions.
- Maintain consistent testing conditions across all samples.
- Repeat measurements when combustion is incomplete or the result fails the method's repeatability criteria.

4. TURBINE HEAT RATE

Turbine heat rate represents the thermal energy supplied to the turbine cycle per unit of electrical generation.

The condensate flow based heat-rate determination using measured cycle heat input and electrical output is used predominantly for all purpose. However there is alternate method, the indirect approach helps identify the causes of performance deviation through detailed analysis of steam conditions, extraction flows, feedwater heaters, condenser pressure and turbine expansion performance, which is not in wide practice.

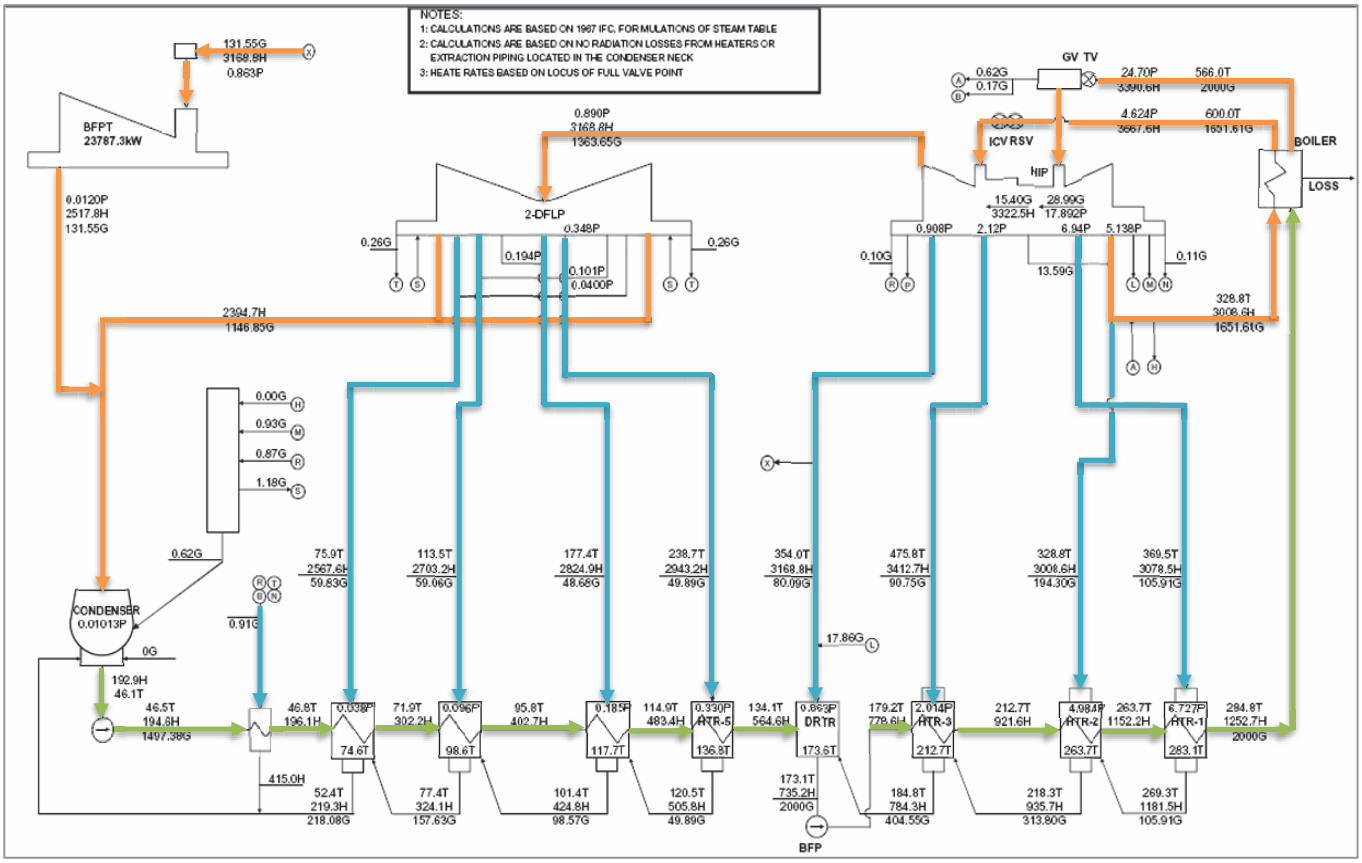
In a thermal power plant, turbine-cycle performance is affected mainly by:

- Main steam pressure and temperature.
- Hot-reheat steam temperature and pressure.
- Turbine internal efficiency.
- Condenser backpressure.
- Regenerative feedwater-heater performance.
- Steam extraction and leakage flows.
- Gland sealing and auxiliary steam consumption.
- Feedwater temperature and cycle configuration.
- Generator output and relevant electrical losses.

An observed increase in turbine heat rate does not necessarily indicate deterioration of the turbine blading alone. It may result from condenser degradation, feedwater-heater performance, steam-condition deviations, flow-measurement errors or changes in the test boundary.

Therefore, an effective performance-assessment methodology must establish both the measured heat rate and the engineering reasons for any deviation from the reference performance.

Typical Heat and Mass Balance Diagram (HMBD) of a 660 MW power plant



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4.1 Turbine Heat Rate Measurement

Turbine heat rate is the thermal energy supplied to the defined turbine-cycle boundary divided by the corresponding electrical output.

For a regenerative Rankine cycle, the cycle heat input includes the applicable main-steam and reheat contributions, with appropriate treatment of spray water and other boundary streams.

For a typical reheated steam cycle, the simplified heat-input expression is:

$$THR = \frac{\dot{m}_{ms}(h_{ms} - h_{fw}) + (\dot{m}_{hrh}\, h_{hrh}) - (\dot{m}_{crh}\, h_{crh})}{P_g}$$

Where:

- $\dot{m}_{ms}$ = main steam mass flow rate. Where it is not measured in high-capacity units, calculated from measured condensate flow and calculated extraction steam flows of Turbine cycle
- h_{ms} = main steam enthalpy at turbine inlet
- h_{fw} = final feedwater enthalpy at the defined cycle boundary
- $\dot{m}_{rh}$= reheater steam mass flow rate after considering reheater spray
- h_{hrh}= hot reheat steam enthalpy
- h_{crh}= cold reheat steam enthalpy
- P_g = gross generator electrical output

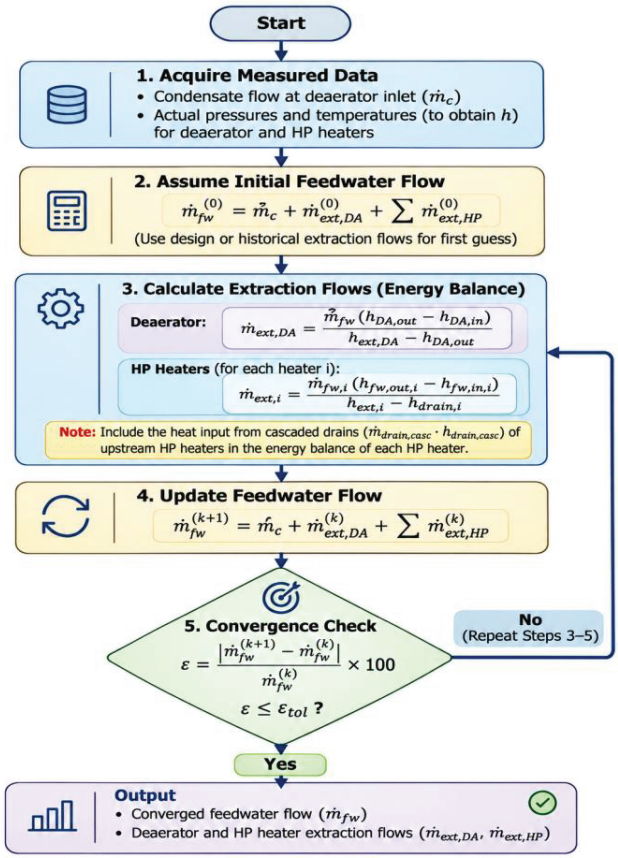
At steady state, the condensate flow can be reconciled with feedwater flow after considering makeup, extractions, blowdown, spray water, auxiliary steam, gland leakage, drains and other applicable streams.

While calculating Main Steam flow, the key point is that ASME PTC 6 does not universally require condensate flow instead of feedwater flow. It permits different primary-flow measurement locations and recommends the location based on the feedwater-heater arrangement and the potential for leakage or recirculation to bias the measurement. Condensate flow is primarily used because,

- To avoid feedwater-heater leakage errors - Consider a cycle in which high-pressure feedwater heaters use extraction steam. If a heater tube leaks, the feedwater flow reading may not represent the intended primary cycle flow accurately.
- Better measurement conditions
  - Lower water temperature, reducing extrapolation of the flow meter's discharge-coefficient calibration.
  - Potentially simpler installation than a high-pressure feedwater line.

This approach requires reliable measurement of condensate flow, pressure, temperature, relevant feedwater conditions and generator output. Reheat and other energy contributions must be treated consistently with the adopted test boundary.

Calculating Main steam flow from Condensate flow through Iteration:



Main steam flow, $\dot{m}_{ms} = \dot{m}_{fw} - \dot{m}_{leak}$

Hot reheat flow = $\dot{m}_{crh} + \dot{m}_{RH\ spray}$

Note: Since accurate measurement of condensate flow is paramount important, so it should be calibrated on periodic interval like during COH/AOH.

Advantages of Condensate flow method of THR calculation

1. Measurement-based result: It establishes heat rate from measured thermal and electrical quantities.
2. Clear physical interpretation: It relates the energy supplied to the cycle to electrical generation.
3. Suitable for performance testing: It can form the basis of a formal turbine test when implemented according to the applicable test code.
4. Useful for comparison: Results can be compared with contractual guarantees or reference performance after the required corrections.
5. Independent of a purely theoretical turbine model: It does not rely solely on predicted component efficiencies.

Limitations

1. Flow-measurement uncertainty: Main-steam and reheat-flow measurements can materially influence the result.
2. Enthalpy uncertainty: Pressure and temperature errors affect calculated steam enthalpy.

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3. Boundary complexity: Extraction flows, leakage, drains, spray water and auxiliary steam must be correctly accounted for.
4. Limited diagnostic detail: A single heat-rate result does not identify which turbine stage or cycle component is responsible for degradation.
5. Correction uncertainty: Deviations from reference conditions may require OEM or test-code correction procedures.

The condensate flow method is therefore valuable for establishing measured performance, but additional analysis is normally required to explain why the result differs from the reference.

4.2 OEM Correction Curves for Thermal Power Plants

OEM correction curves are essential tools for evaluating boiler, steam-turbine and overall plant performance when actual test conditions differ from the specified reference or design conditions.

The fundamental purpose is to separate the effect of operating conditions from the actual equipment performance. For example, a turbine may show a higher heat rate during a test because condenser pressure is higher than the reference value, even though the turbine itself has not deteriorated.

ASME PTC 6 addresses corrections for steam-turbine tests, while ASME PTC 46 addresses correction of overall plant performance to reference conditions. The correction methods should be appropriate to the actual unit and test boundary.

OEM correction curve:

An OEM (Original Equipment Manufacturer) correction curve is a graph, table or mathematical relationship that predicts how a performance parameter changes when a particular operating variable deviates from its reference value.

Typical performance parameters being corrected are:

- Boiler efficiency
- Turbine heat rate (kcal/kWh)
- Turbine power output (MW)
- Overall gross or net heat rate
- Condenser and auxiliary-equipment performance, where applicable

For example, a turbine manufacturer may provide a curve showing how turbine heat rate changes with condenser pressure while keeping the other specified conditions constant.

OEM correction curves are normally developed during turbine-cycle design and performance modelling, then finalized using the performance information for the supplied equipment and the agreed plant configuration.

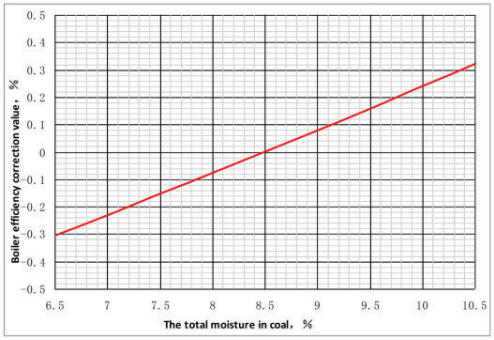
Major correction curves for a steam Boiler:

These curves, generally developed by the boiler OEM based on design calculations and thermal performance models, quantify the influence of deviations in parameters such as unit load, coal quality, moisture, excess air, flue-gas exit temperature and mill configuration on boiler efficiency and associated heat losses.

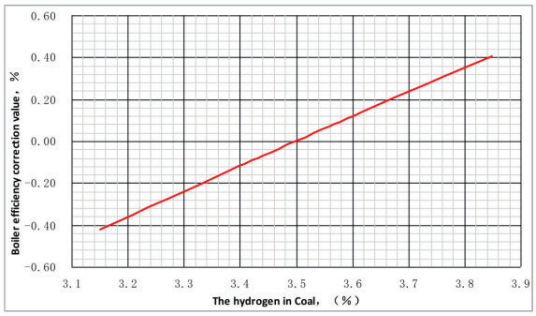
By applying the appropriate corrections, measured performance can be normalised to specified reference conditions, enabling a more meaningful comparison with design guarantees and historical benchmarks.

Examples of variables universally considered for correction while evaluating Boiler efficiency are,

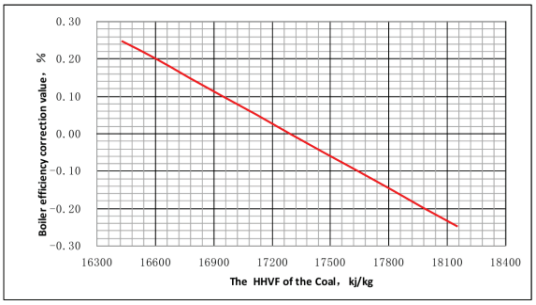
(a) Total moisture in coal



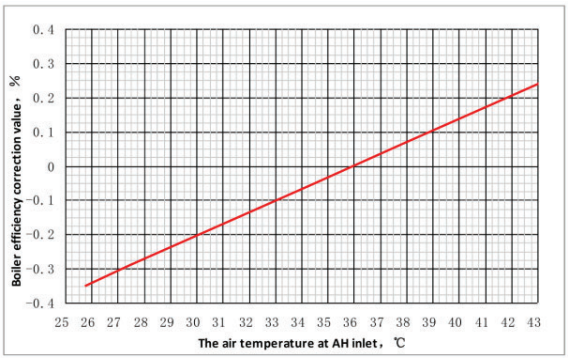
(b) Hydrogen in coal



(c) Gross Calorific Value (HHV) of coal



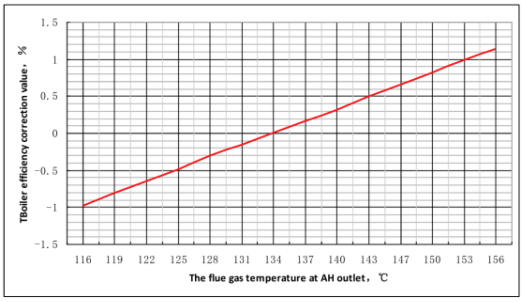
(d) Air temperature at AH inlet



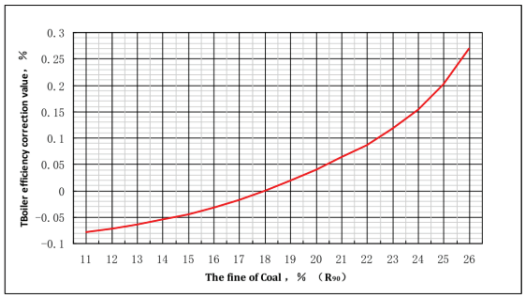
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(e) Flue gas temperature at AH outlet



(f) The fineness of Coal



Major correction curves for a steam turbine

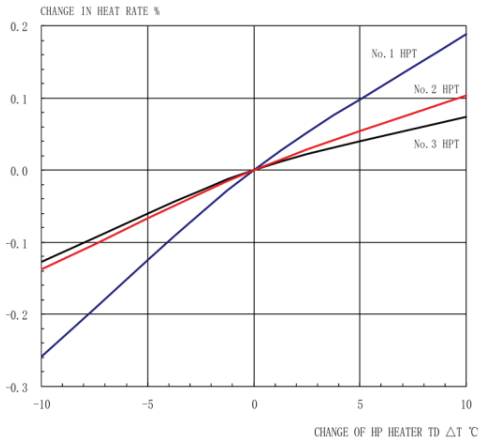
ASME PTC 6 distinguishes between corrections associated primarily with cycle parameters and those associated primarily with turbine operating conditions. The exact classification and applicable variables should be checked against the governing edition and test procedure.

Tests shall be conducted with the smallest possible deviation from specified conditions, to minimize correction error. Corrections for deviations from the specified operating conditions may conveniently be separated into two groups, as follows.

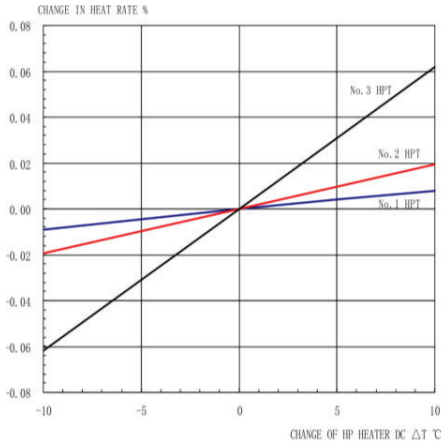
Group 1 Corrections: This group includes corrections for variables primarily affecting the feed heating system and generator-operating conditions. Turbines should not be penalized because of the reasons which are not attributable to turbines itself.

Examples of variables included in Group 1 are,

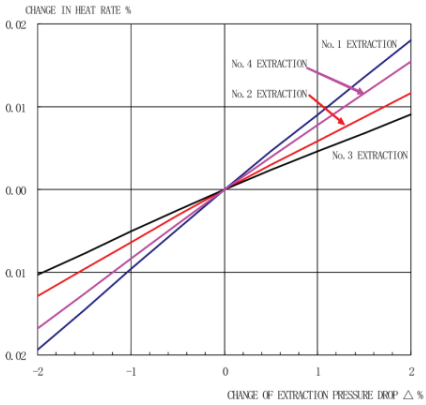
(a) feedwater heater terminal temperature differences



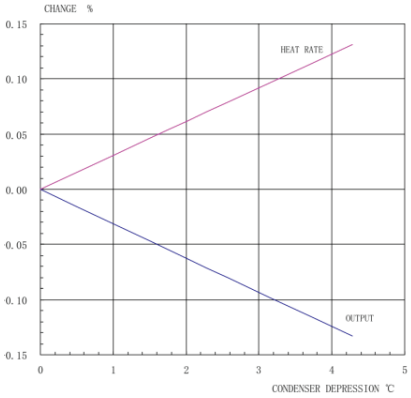
(b) feedwater heater drain-cooler approach differences



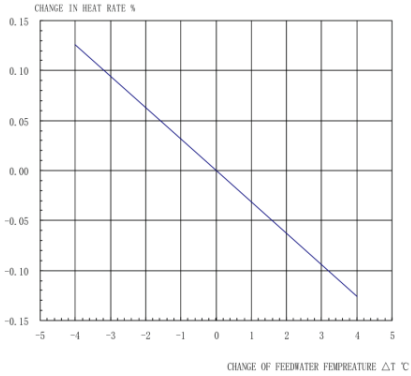
(c) extraction line pressure drops and heat losses



(d) condenser-condensate temperature depression



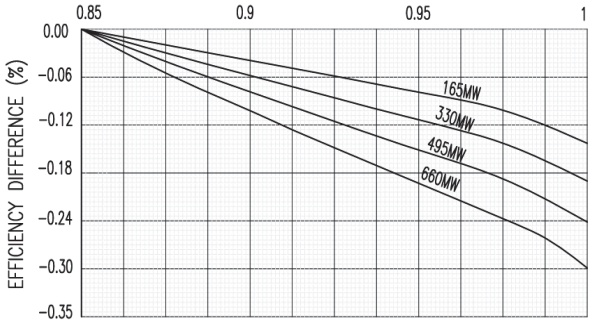
(e) Final feedwater temperature



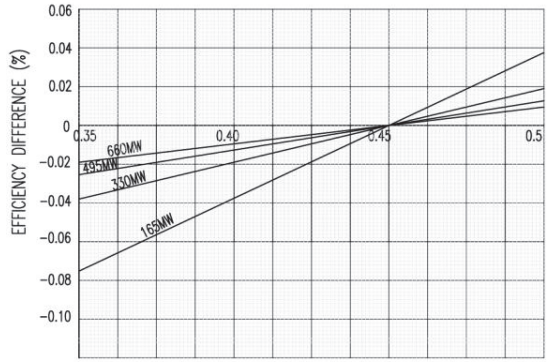
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(f) power factor,



(g) generator hydrogen pressure

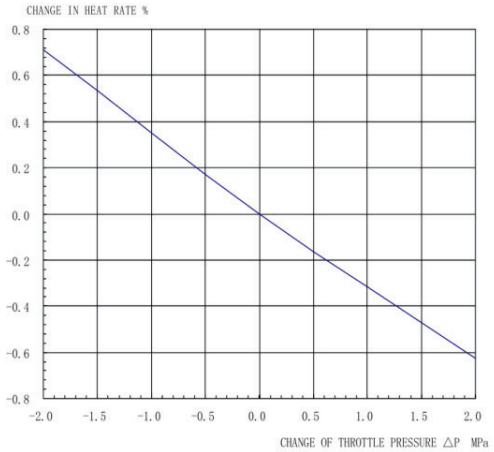


Group 1 cycle corrections can be made by heat balance calculation or application of correction curves or tables. In the heat balance method, the test cycle may be corrected to the specified cycle or vice versa.

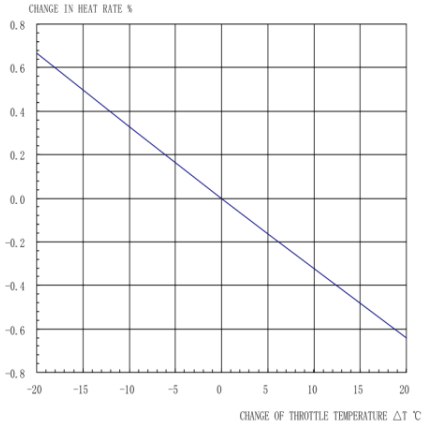
Group 2 Corrections: This group includes corrections of variables primarily affecting the turbine performance, which are like steam conditions at turbine inlet, reheater and turbine exhaust.

Examples of variables included in Group 2 with their impact on turbine heat rate are,

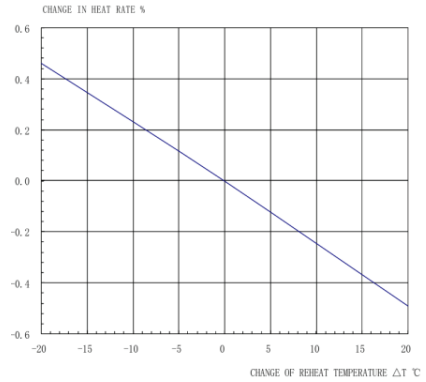
(a) turbine initial steam pressure



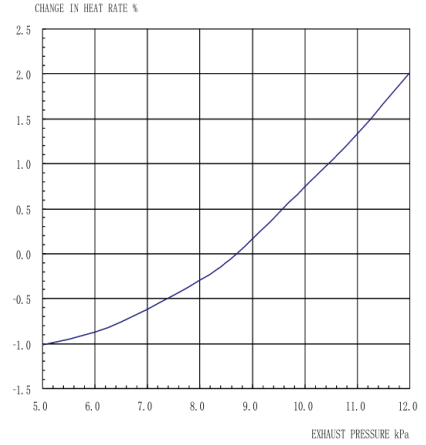
(b) turbine initial steam temperature



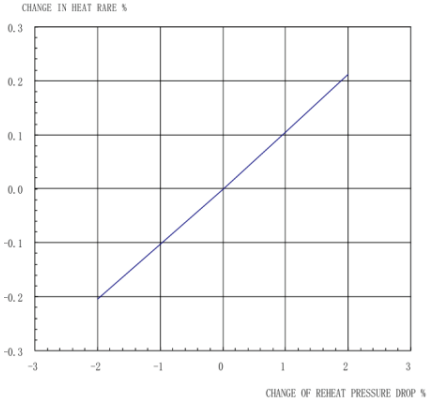
(c) turbine hot reheat steam temperature



(d) turbine exhaust pressure



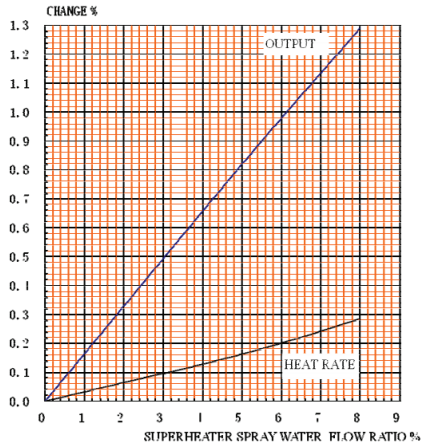
(e) pressure drop of steam through the reheater system(s)



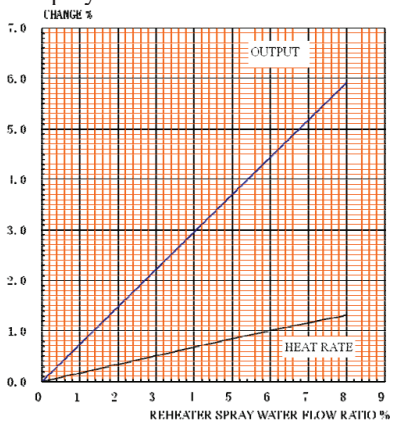
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(f) Super heater spray flow ratio



(g) Reheater spray flow ratio



A correction curve should be applied only to the performance variable and boundary for which it was developed.

Correction curves applying methodologies

There are two common approaches, depending on the approved test procedure.

a. Additive correction

$$R_{\text{corrected}} = R_{\text{measured}} + \Delta R$$

b. Multiplicative correction

$$R_{\text{corrected}} = R_{\text{measured}} \times CF$$

Here, R is the measured performance parameter, ΔR is the correction obtained from the curve and CF is the applicable correction factor.

The THR corrected to specified reference or design conditions using the applicable OEM correction curves or ASME PTC 6 correction procedures. The purpose is to compare turbine performance fairly when actual test conditions differ from the reference conditions.

If the measured turbine heat rate is corrected using multiplicative correction factors:

$$THR_{\text{corrected}} = \frac{THR_{\text{measured}}}{F_{\text{combined}}}$$

Where,

$$F_{\text{combined}} = F_1 F_2 F_3 \cdots F_n$$

The factors may account for deviations in main steam pressure and temperature, reheat temperature, condenser pressure, and other parameters covered by the specific OEM procedure.

Important: This divisor convention applies only when the OEM defines the correction factors that way. Some OEM procedures use a different convention.

Assessment of Unaccounted Turbine Heat Rate (THR) Loss After Corrections

The condensate-flow-based direct method provides an independent estimate of turbine heat rate (THR) using measured cycle heat input and gross generator output. However, the calculated value may deviate from the OEM design heat rate or the reference-condition heat rate even after applying the prescribed correction factors for main steam pressure and temperature, reheat temperature, condenser pressure, and other relevant operating parameters.

The residual difference, termed the unaccounted THR deviation, is determined by comparing the corrected measured THR with the corrected reference THR:

$$\Delta THR_{\text{unaccounted}} = THR_{\text{measured,corr}} - THR_{\text{reference,corr}}$$

The percentage deviation is:

$$\%\Delta THR = \frac{\Delta THR_{\text{unaccounted}}}{THR_{\text{reference,corr}}} \times 100$$

This residual represents the combined effect of performance deterioration, measurement uncertainty, calculation-boundary differences, and operating parameters not fully captured by the applied corrections. Potential contributors include turbine internal efficiency deterioration, feedwater-heater degradation, extraction-steam leakage, gland-seal losses, cycle leakage, condensate-flow measurement bias, and inaccuracies in steam/water enthalpy calculations.

A structured gap analysis should therefore reconcile the condensate-flow-based heat input with the applicable turbine-cycle heat balance, verify instrumentation calibration and mass-balance closure, confirm the OEM correction curves and reference conditions, and quantify test uncertainty. Only after these checks should the remaining deviation be attributed to genuine turbine-cycle performance deterioration.

Scientific interpretation: The unaccounted THR deviation is a residual performance gap, not a direct measurement of a single loss mechanism. Its attribution requires supporting thermodynamic analysis and uncertainty assessment, preferably following the applicable ASME PTC 6 methodology and the defined test boundary.

Limitations on applying correction curves

Correction curves should not be applied indiscriminately like,

- Outside the validated range: Do not extrapolate beyond the curve's approved operating range without technical justification.
- Wrong turbine or unit configuration: A curve for a different turbine design or cycle arrangement may not represent the actual unit.
- Wrong reference conditions: The reference condition and correction convention must match the test procedure.
- Double correction: Do not apply a correction twice if the test calculation or model has already accounted for it.

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- Unverified generic curves: Generic ASME curves may not accurately represent a particular turbine. OEM-specific curves or a validated unit-specific model should be preferred when required and available.
- Large deviations or interacting variables: A simple independent-factor approach may be inadequate; a detailed heat-balance calculation may be required.
- Routine operation outside test conditions: A test correction curve is not necessarily a substitute for a validated online performance model.

OEM correction curves are mathematical representations of how equipment performance changes with operating conditions. They are developed from design and thermodynamic performance models, applied to normalize test results to common reference conditions, and used in acceptance testing, routine monitoring and pre-/post-outage comparisons.

Best Practices for Reliable Turbine Heat-Rate Assessment

For a thermal power generating unit, the following practices are recommended while conducting Turbine heat rate test:

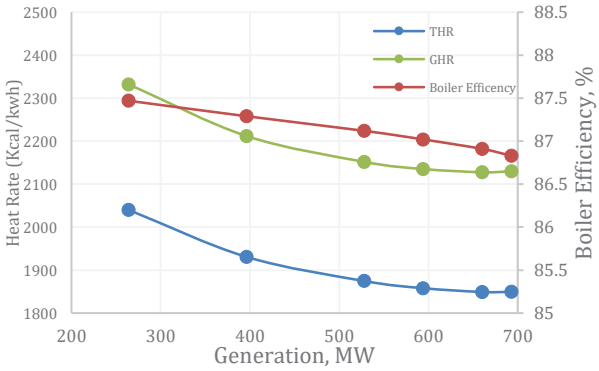
- Verify main-steam, reheat and relevant feedwater-flow measurements. Calibrate pressure and temperature instruments used for enthalpy calculations.
- Verify condenser absolute-pressure measurements.
- Reconcile condensate and feedwater flows with other cycle streams.
- Use unit-specific OEM correction curves within their applicable ranges.
- Quantify measurement uncertainty and test repeatability.
- Compare measured performance with corrected reference performance.
- Investigate direct-versus-model discrepancies instead of averaging inconsistent results.

5. GROSS AND NET HEATRATE

Direct gross heat rate is the fuel heat input divided by gross generation:

$$GHR = (\dot{m}f \times GCV) / P_G$$

Typical relation between Unit generation with Turbine heat rate, Boiler efficiency and Gross heat rate.



If auxiliary power is represented as a fraction of gross generation (APC),

$$NHR = GHR/(1-APC).$$

6. HEAT-RATE GAP ANALYSIS

A heat-rate result becomes useful for plant improvement only when the gap is identified and analyzed for corrective actions. A practical representation is:

$$GHR_{actual} = GHR_{design} + \Sigma\Delta HRi$$

Contributors for heat rate deviations,

Boiler side	Turbine side	Aux Power (APC)
Excess air	Turbine internal-efficiency degradation	High ID/FD/PA fans power consumption
Exit flue gas temperature	Condenser backpressure	CEP/BFP power consumption
Air-heater leakage	Feedwater-heater performance	Coal mills power consumption
Poor combustion & Unburned carbon	Main and reheat steam deviation	Coal handling power consumption
Poor coal fineness	Feedwater-temperature	ESP & ash handling power consumption
High spray-water consumption		Cooling-water systems power consumption
Slagging/fouling		

The recommended management sequence is: Design GHR → Corrected Reference GHR → Measured GHR → Gap analysis → Corrective Actions.

7. ACCURACY, UNCERTAINTY AND REPEATABILITY

Accuracy and repeatability are different properties. Repeatability indicates how closely repeated tests agree under substantially identical conditions; accuracy concerns closeness to the true value. Three closely agreeing results can still be systematically biased. Therefore, calibration traceability and uncertainty analysis are required in addition to repeat testing.

For repeated runs, the percentage difference between two results may be expressed as $|R1-R2| / [(R1+R2)/2] \times 100$. The test procedure should define the number of runs, stability requirements, allowable parameter deviations, repeatability criterion and treatment of rejected runs before testing begins.

The uncertainty control should focus attention on measurements that materially influence the final result. Typical dominant contributors include coal flow and GCV for direct GHR, steam flow and enthalpy for THR, generator output, condenser pressure and major correction factors.

8. TEST PREPARATION AND BEST PRACTICES DURING PG TEST

- Freeze the test procedure, boundary, reference conditions and calculation methodology before the test.
- Verify calibration certificates, ranges, installation and data-acquisition channels for critical instruments.
- Use independent or redundant measurements for dominant parameters wherever practical.

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- Stabilize load, steam conditions, coal flow, spray flows, condenser conditions and auxiliary configuration before the official run. As per author experience, operating unit in stable condition for minimum 1 hour required before start of PG test.
- Collect representative coal and ash samples and document sample identification and laboratory results.
- Record raw test data continuously and preserve the complete data set.
- Verify analyzer drift and sampling-system integrity before and after the test.
- Apply only approved correction curves within their validated range.
- Conduct duplicate or repeat runs and investigate unexplained differences rather than simply averaging
- Report rejected runs and the technical basis for rejection.
- Using approved Thermodynamic Properties of Water and Steam.

Best Practices during Routine O&M phase Test:

- Use the same calculation sheets, test boundaries, units and reference conditions every month.
- Define the target load band and required steady-state period.
- Document the running mills, burners, fans, pumps, soot-blowing status and other relevant equipment configurations.
- Record unavoidable disturbances rather than silently excluding or averaging them away.
- Verify calibration status and instrument health before the test.
- Check flow-meter compensation, pressure and temperature sensor consistency, O_2/CO analyser health, and the validity of coal sampling and GCV results.
- Stabilize condensate flow
- Ensure maximum possible coal mill outlet temperature
- If Air preheater provided with leakage control system, ensure the seals are at possible minimum gap without current hunting
- Synchronize timestamps across DCS, CEMS, laboratory results and portable instruments.
- Retain raw readings alongside averaged values and calculated results.
- Keep measured, corrected and reference-condition results separate.
- Compare with the design/reference condition and the previous month under comparable conditions.
- Track uncertainty and distinguish genuine deterioration from measurement noise.
- Investigate unexplained residuals before assigning them to a particular component.
- Identify the dominant performance gaps and their likely causes.
- Implement corrective action and verify with expected improvement.

9. DO'S AND DON'TS DURING TESTING

Do

- Maintain the agreed mill combination and operating configuration.
- Maintain stable main-steam/reheat conditions and condenser operation.
- Cross-check DCS values against dedicated test instrumentation.
- Reconcile independent energy balances before accepting the result.
- Document every operational intervention during the test.

Don't

- Do not depend entirely on routine DCS measurements without validation.
- Do not mix as-received, air-dried and dry-basis GCV values.
- Do not use non-representative coal samples.
- Do not extrapolate OEM correction curves outside their validated range.
- Do not interpret a small heat-rate change as a real improvement unless it is significant relative to test uncertainty and repeatability.

10. REALTIME PERFORMANCE ASSESSMENT

Real-time performance assessment is essential for achieving sustained operational efficiency and minimising avoidable energy losses in thermal power plants. Continuous monitoring of critical performance parameters enables deviations from design and optimum operating conditions to be identified promptly, facilitating timely corrective actions before minor inefficiencies develop into significant performance losses.

By integrating real-time process data, fuel-quality information, engineering-based performance calculations and advanced analytical tools, the system provides actionable insights into boiler, turbine-cycle and auxiliary equipment performance. It also supports early identification of equipment degradation, predictive maintenance planning and continuous verification of implemented improvement measures.

Typical Performance dashboard of power plant



Ultimately, real-time performance assessment transforms conventional retrospective performance monitoring into a proactive, data-driven approach, contributing to reduced heat rate, lower auxiliary power consumption, improved equipment reliability, reduced operating costs and enhanced overall plant efficiency.

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Integration of artificial intelligence for advanced performance analytics:

Integration of Artificial Intelligence (AI) and machine-learning capabilities can further enhance the effectiveness of the performance monitoring platform. Beyond conventional parameter monitoring and threshold-based alarms, AI can leverage historical and real-time operating data acquired from the DCS to perform the thermodynamic calculations and performance assessments described in the preceding sections in the backend.

By applying advanced analytics and machine-learning techniques, the system can identify complex relationships, quantify heat-rate gaps, recognise abnormal operating patterns, assess performance under dynamic operating conditions and detect gradual equipment deterioration. The insights are presented through integrated performance dashboards, highlighting deviations, potential root causes and recommended corrective actions for Operations and Maintenance (O&M) engineers. This enables timely operational interventions, proactive maintenance planning and continuous performance optimisation, thereby minimising avoidable energy losses and improving overall plant efficiency and reliability.

Potential applications of AI integration include:

1. **Role-based report generation:** Automatically generate customised reports for plant management, operations, maintenance, performance monitoring and energy management teams.
2. **Advanced performance insights:** Identify the underlying contributors to deviations in heat rate, boiler efficiency, auxiliary power consumption and equipment performance.
3. **Pattern recognition:** Detect gradual performance degradation, abnormal operating behaviour and recurring inefficiencies that may not be apparent through conventional monitoring.
4. **Predictive maintenance support:** Identify early indicators of equipment deterioration and support maintenance planning based on condition and performance trends.
5. **Performance optimisation:** Recommend corrective actions based on operating conditions, historical performance and established engineering limits.
6. **Automated reporting:** Generate daily, weekly and monthly performance summaries, deviation reports and management dashboards.

Advantages of integrating energy management and performance monitoring into a single platform

Integrating energy management and performance applications into a unified tool eliminates fragmented data systems and provides a common platform for energy accounting, equipment performance evaluation and operational decision-making.

Key advantages include:

- **Single source of information:** Common operational database for energy accounting, performance monitoring and analytical applications.
- **Improved data consistency**: Avoids duplication of data acquisition, manual data transfer and inconsistencies between different applications.
- **Integrated energy accounting:** Links fuel consumption, electrical generation, auxiliary consumption and equipment-wise energy performance.
- **Historical benchmarking:** Enables comparison across operating periods, load conditions, fuel qualities and equipment configurations.

  Continuous improvement: Creates a feedback loop between performance assessment, corrective action and verification of achieved savings.
- **Improved accountability:** Role-based dashboards and reports establish clear ownership of performance gaps and corrective actions.
- **Reduced software and maintenance overhead:** Consolidates multiple applications, interfaces and reporting systems.

Secure data integration:

A secure and controlled data architecture is essential for integrating plant Operational Technology (OT) with Information Technology (IT) systems while protecting critical control infrastructure.

The architecture should ensure that process data flows from the OT network to the IT network through a unidirectional, secure communication arrangement, without allowing external systems to write back to the plant control network.

The principal data integration architecture comprises,

DCS Historian: Stores time-series operational data acquired from the DCS, enabling historical trending

Firewall: Acts as a security barrier between OT and IT network segments. It controls and filters network traffic based on predefined security policies, restricting unauthorized access and communication.

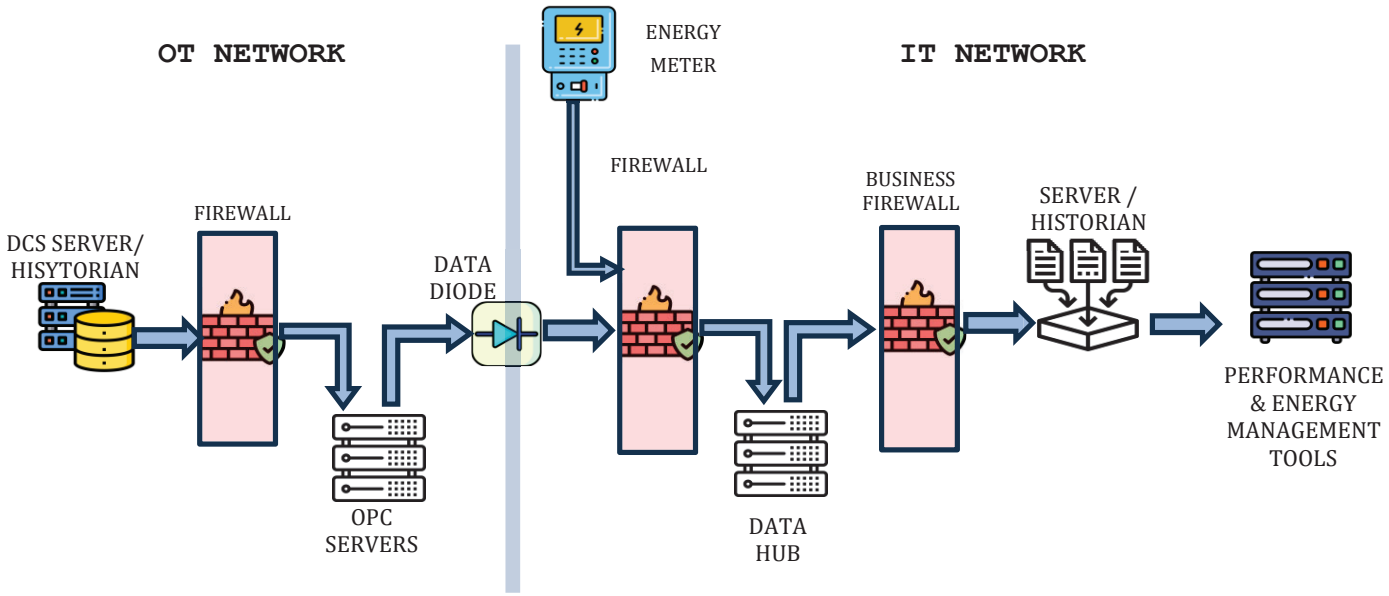
OPC Server (Open Platform Communications): Collects real-time process data from the DCS, including operating parameters, equipment status and measurements, and makes the data available to authorised applications through standardised communication interfaces.

Data Diode: Provides hardware-enforced unidirectional data transfer from the OT network to the IT network to have cyber security

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Typical architecture of secure data integration:



11. CONCLUSIONS

Accurate performance measurement of a thermal power plant requires measurement-driven and uncertainty-controlled methodology. The most important practical requirements are reliable coal flow and GCV measurement, accurate steam-flow and enthalpy determination, verified generator output, appropriate OEM corrections, stable operating conditions, repeatability and uncertainty analysis.

The final objective should not simply be a single heat-rate number. A high-quality performance test should establish the actual performance, quantify the confidence in the result and decompose the gap into boiler, turbine, condenser, auxiliary-power and measurement contributors. This converts performance testing from a periodic compliance activity into a continuous plant-performance management system.

The integration of real-time performance monitoring, energy management and AI-based analytics offers a significant opportunity to enhance the operational efficiency of thermal power plants. A secure OT–IT data integration architecture, supported by reliable fuel-quality inputs and automated engineering calculations, enables continuous performance assessment and timely identification of avoidable losses. Implementing these capabilities through a single integrated

12. REFERENCES

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