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A New Approach for Model-Based Monitoring of Turbine Heat Rate

In this paper, a new approach for model-based monitoring of turbine heat rate is developed, where the superheat steam flow is calculated according to the output power of the turbine generation instead of the flow of feed water. A regenerative system model is built based on the operating state and historical data to predict the parameter values in the heat rate calculation. The results of the model calculation also verify the turbine operating parameters that are measured on site. The new approach in this paper was applied in a 660 MW generation unit. The monitoring results of this approach are more stable and accurate than traditional monitoring results. [DOI: 10.1115/1.4034231]

Keywords: heat rate, model-based soft measurement, online monitor, turbine

1 Introduction

Thermal efficiency online monitoring of the thermal system plays an important role in the device operation safety and economics [1,2]. Accurate and stable online monitoring of the turbine heat rate implies great energy conservation and emission reduction.

The researches distribute on different monitoring objects. Kumar et al. [3] described monitor vibration condition of boiler feed pump (BFP) unit. Cai et al. [4] introduced a novel online monitoring performance method of coal-fired power unit to predict the unburned carbon content of fly ash in the boiler and the exhaust steam enthalpy in turbine. Hermansson et al. [5] presented an online monitoring of the moisture content of the fuel in a furnace based on the measurement of the relative humidity of the flue gases from a furnace. Bolatturk et al. [6] studied the thermal and second law efficiencies of Çayırhan thermal power plant and analyzed the amounts of exergy losses for each part of the plant. Fu et al. [7] proposed a numerical model for feedwater heating allocation problem in selecting the optimum feedwater heating allocation of large capacity steam turbine unit. Geete and Khandwawala [8] calculated the power output and the heat rate changing due to extraction line pressure drop of heaters. Wang et al. [9] presented a modified differential evolutionary algorithm for optimizing the design of steam cycles. Tangwe et al. [10] proposed an innovative optimization technique on performance efficiency verification in a coal thermal power plant unit. Hanak et al. [11] provided a methodology for modeling of part-load operation of coal-fired to evaluate the process performance under different operating loads. Petrakopoulou et al. [12] presented an evaluation of the environmental performance of an advanced zero emission plant including CO_2 capture.

The steam turbine heat rate is an important economic indicator. Thermal performance experiments are a typical way to monitor the steam turbine heat rate accurately, but it could not be used as online monitoring of heat rate. Regression methods and data-reconciliation methods have been proposed to determine the turbine heat rate. Zhang et al. [13] provided a heat rate forecasting method based on online least squares support vector machine (LS-SVM). Liu et al. [14] proposed a novel soft computing method, based on LS-SVM and gravitational search algorithm to forecast heat rate of a 600 MW supercritical steam turbine unit. Wirski [15] proposed a statistical analysis of data for modification of the current power plant performance calculation methodology. Munukutla [16] presented a unified method of performance evaluation with a consistent set of definitions for boiler efficiency, steam-cycle efficiency, and finally the overall unit efficiency. The neural network models [17,18] are usually applied in optimizing works. These methods are based on large amount of historical operating parameters, and the models will be less accurate over time due to equipment aging and modification.

Currently, most thermal power plants use the supervisory information system (SIS) at the plant level to monitor (based on the

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standard of ASME PTC-6 2004) the operation of the generation unit. This traditional heat-rate-monitoring is based on the measurement of the feed water flow using an ASME standard orifice, which is installed at the export of the deaerator (DEA). The measuring precision of this method is determined by the precision of the feed water flow measurement. Jiang et al. [19] proposed a data-reconciliation approach in steam turbine online performance monitoring, with the aim of reducing uncertainty of the primary flow measurements and steam turbine heat rate.

When the standard orifice is used to measure the feed water flow, the flow is calculated using the below equation

$$D = \alpha\varepsilon A\sqrt{2\rho\Delta P} \quad (1)$$

where D is the flow, α is the flow coefficient, ε is the expansion factor, A is the pipe area, ρ is the water density, and ΔP is the pressure difference.

In addition to the pressure difference, the other parameters are usually experimentally calibrated and affected by the operating conditions. In particular, the flow coefficient and density significantly change when the output of the generating unit changes. In addition, when the power unit operates, the flow orifice bends and deforms, and the entrance has edge wear or corrosion. These circumstances result in the measurement inaccuracy.

Figure 1 shows the curves of heat rate and power load of a generation unit of South China in 1 day. It is observed from the figure that in zones 1 and 4, the load greatly decreases while the heat rate increases very slightly, which is not consistent with the operating characteristics of the power unit. In zone 2, the load significantly changes (corresponding to 660 MW and 540 MW), but the heat rate measured using the SIS stays unchanged. In zone 3, the correlations between the heat rate and the load change are poor. In this area, the load is stable, but the heat rate obviously fluctuates.

The numerical techniques [20–23] enable an accurate simulation with complex computation. The mathematical models [24–28] are less complex for describing the physical phenomena than numerical models. The development of these modeling works makes the soft measurement based on models reliable.

In this paper, a new approach to monitor the turbine heat rate based on a regenerative model is presented in this paper to overcome the error of the flow measurement. The superheat steam flow is calculated according to the output power of the turbine generation instead of the flow of feed water. The historical operating parameters, the design data, and the thermal performance test results of the steam turbine are used to establish an expert knowledge database for verifying the online collected parameters. The application example for a 660 MW generation unit showed that the presented method is more stable and accurate than traditional monitoring method.

The remainder of this paper is organized as follows: Section 2 describes the flow schematic diagram of the new measurement. Section 3 presents the model approach for regenerative system. Section 4 describes the heat rate calculation equations. Section 5 presents an application example for a 660 MW generation unit in China. Finally, Sec. 6 concludes the paper.

2 Measurement Method

Considering the heat-rate-monitoring problem due to the flow measurement error, the work in this paper analyzed the mechanism of the regenerative system, the measurement accuracy, and the stability of various thermal measuring meters and found that the measurement of the output power of the turbine is rarely influenced by load and external-condition changes. Hence, the new measurement method is a soft measurement based on the output power of the turbine. Figure 2 shows the flow schematic diagram of the new measurement, which includes the following steps:

(1) Establish an expert knowledge database of the thermal performance. The database should include the design data, the thermal system principle diagram, the historical operating data, and the thermal performance test results of the steam turbine regenerative system to provide necessary data to build the simulation model.
(2) Collect the operating data on site. The pressure and temperature of the main steam and reheat steam must be collected.
(3) Establish a full process simulation model of the regenerative system according to the design data of the unit, heat conservation principle, and operating mechanism. The development of the model is based on the data from the expert database. These data are used to calculate the temperature difference of the heaters, the pressure ration between import and export of the turbine stage, and the pressure loss of the extraction pipe.
(4) Calculate the parameter value. That is, to calculate the data, which is needed by the heat consumption calculation, by the model.

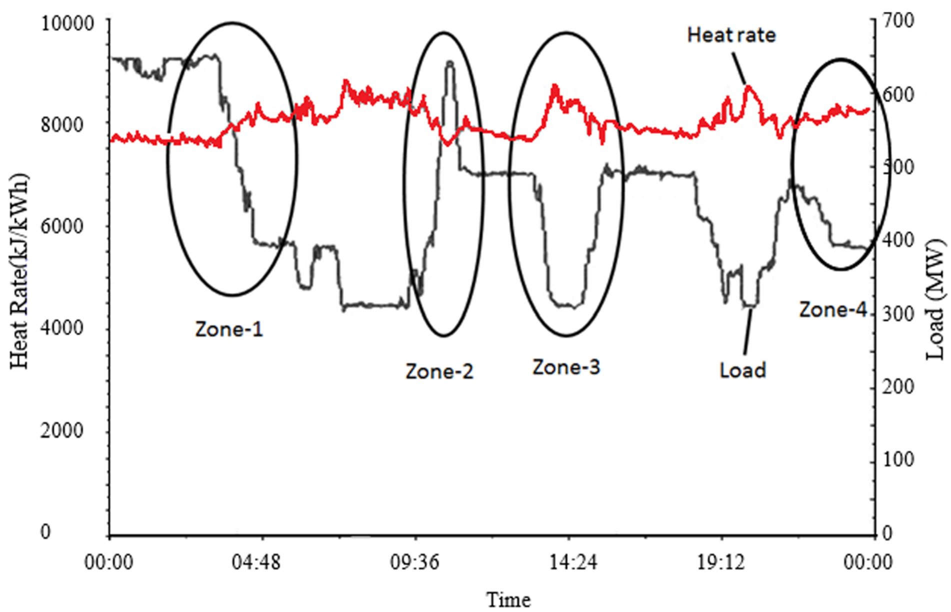

Fig. 1 Measurement results of heat rate using the SIS

(5) Verify the data that are measured. A few data measured could be wrong data due to sensor fault. By calculating the difference between the measured and calculated data to determine whether the data are credible. The difference threshold is set according to the importance of parameter or the precision of the sensors. If the difference is greater than the threshold, then use the model-calculated values to replace the measured values.
(6) Fill the heat rate calculation by the data measured. If the data are not measured on site, then use the model-calculated values to complete the calculation.
(7) Calculate the turbine heat rate.
Hence, the main step of the measurement method is to build a proper model for the regenerative model.

3 Model Approach for Regenerative System

This model mainly calculates the extraction pressure, heater inlet pressure, and thermal temperature difference (TTD) of the heaters; drain cooler approach difference (DCA) of the heaters; and the steam turbine exhaust enthalpy.

The extraction pressure is calculated using the below equation

$$P_j = \varepsilon_j \cdot P_{j-1} \tag{2}$$

where P_j is the extraction port pressure of the j stage, P_{j-1} is the extraction pressure of the upper stage, ε_j is the pressure ration between import and export, and j is the number of stage.

The extraction temperature is calculated using the below equations

$$T_j = f_{t\_\mathrm{ph}}(P_j, h_j) \tag{3}$$

$$h_j = (1-\eta_j)h_{j-1} + \eta_j h_j' \tag{4}$$

where T_j is the extraction temperature of the j stage, $f_{t\_\mathrm{Ph}}()$ is a function to calculate the temperature of steam in the state of pressure P_j and enthalpy h_j, η_j is the efficiency of the j stage, and h_j' is the ideal enthalpy of the j stage.

The heater inlet pressure is calculated using the below equation

$$P_{\mathrm{in},j} = (1-\beta_j) \cdot P_j \tag{5}$$

where $P_{\mathrm{in},j}$ is the inlet pressure of the heater, and β_j is the pressure loss of the extraction pipe.

The TTD and DCA of the heaters are calculated using the below equations

$$\mathrm{TTD}_j = \theta_j \tag{6}$$

$$\mathrm{DCA}_j = \omega_j \tag{7}$$

The exhaust enthalpy is calculated using the below equation

$$h_c = (1-\eta_{\mathrm{LP}})h_{\mathrm{LP}} + \eta_{\mathrm{LP}} h_c' \tag{8}$$

where h_c is the exhaust enthalpy of the low-pressure cylinder, h_{LP} is the inlet enthalpy of the low-pressure cylinder, h_c' is the ideal enthalpy of the low-pressure cylinder, and η_{LP} is the efficiency of the low-pressure cylinder.

Although the exhaust enthalpy of the low-pressure cylinder can be calculated using Eqs. (3) and (4), the inlet enthalpy of the low-pressure cylinder can be accurately estimated using the outlet steam temperature of the DEA. As a result, the exhaust enthalpy of the low-pressure cylinder should be calculated using Eq. (8).

The parameters ε_j, β_j, θ_j, ω_j, η_j, and η_{LP} in the regenerative model should be determined using the expert database before calculating the heat rate. The method to evaluate these parameters is discussed in detail in Sec 5.2.

4 Heat Rate Calculation

The superheat steam flow is calculated using the below equations

$$D_0 = \frac{3600 P_e}{M \eta_m \eta_g} \tag{9}$$

$$M = h_0 + a_{\mathrm{crh}}(h_{\mathrm{hrh}} - h_{\mathrm{crh}}) - \sum_1^n \frac{D_{zf,k}}{D_0} h_{zf,k} - \sum_1^z a_j h_j - a_c h_c \tag{10}$$

where D_0 is the superheat steam flow, α_{crh} is the cold reheat steam coefficient, α_j is the extraction steam coefficient, z is the number of stages, $D_{zf,k}$ is the shaft seal leakage steam flow, n is the number of shaft seal leakages, α_c is the exhaust steam coefficient, η_g is the generator efficiency, η_m is the mechanical transmission efficiency, h_0 is the superheat steam enthalpy, h_{crh} is the cold reheat steam enthalpy, h_{hrh} is the hot reheat enthalpy, h_j is the extraction steam enthalpy, $h_{zf,k}$ is the shaft seal leakage enthalpy, and h_c is the exhaust steam enthalpy.

All of the mentioned steam enthalpy parameters in this paper can be calculated according to the IFC-67 or IAPWS-IF97 steam parameter calculation model (if the extraction port works in wet-steam status, the steam enthalpy should be calculated based on the dryness of the extraction, which is generally measured or referred to the design data).

The extraction steam coefficient is calculated using Eq. (11)

$$\alpha_j = \frac{\alpha_{f\mathrm{w},j}(h_{\mathrm{fw},j,o} - h_{\mathrm{fw},i,o}) - \alpha_{sj}(h_{sj,o} - h_{sj,i})}{h_j - h_{sj,o}} \tag{11}$$

where α_j is the extraction steam coefficient, $\alpha_{\mathrm{fw},j}$ is the feed water coefficient, α_{sj} is the drain coefficient, $h_{\mathrm{fw},j,o}$ is the feed water outlet enthalpy, $h_{\mathrm{fw},j,i}$ is the feed water inlet enthalpy, $h_{sj,o}$ is the drain outlet enthalpy, and $h_{sj,i}$ is the drain inlet enthalpy.

The temperatures of the feed water and the drain are calculated using the below equations

$$T_{\mathrm{fw},j,o} = T(P_{\mathrm{in},j}) - \mathrm{TTD}_j \tag{12}$$

$$T_{\mathrm{sjo}} = T_{\mathrm{fwji}} + \mathrm{DCA}_j \tag{13}$$

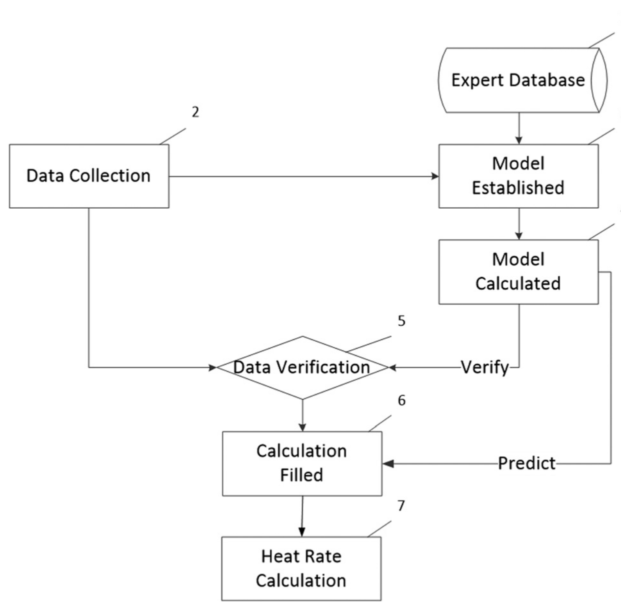

Fig. 2 Flow chart of the method presented in this paper

where $T_{\text{fw},j,o}$ is the feed water outlet temperature, $T_{sj,o}$ is the drain outlet temperature, and $T(P_{\text{in},j})$ is the saturation temperature that corresponds to the pressure $P_{\text{in},j}$.

The cold reheat steam coefficient is calculated using the below equation

$$\alpha_{\text{crh}} = 1 - \sum_{1}^{z} \alpha_j - \frac{D_z}{D_0} \tag{14}$$

where D_z is the flow cooling steam from the first stage to the intermediate-pressure cylinder.

The hot reheat steam coefficient is calculated using the below equation

$$\alpha_{\text{hrh}} = \alpha_{\text{crh}} + \frac{D_{\text{rhsp}}}{D_0} \tag{15}$$

where D_{rhsp} is the flow of desuperheating spray for reheat steam

The feed water coefficient is calculated using the below equation

$$\alpha_{\text{fw}} = 1 + \frac{\Delta D}{D_0} + \frac{D_{\text{shsp}}}{D_0} \tag{16}$$

where ΔD is the unknown leakage steam flow, and D_{shsp} is the desuperheating spray for superheat steam.

The extraction steam coefficient is calculated using the below equation

$$\alpha_c = 1 - \frac{\Delta D}{D_0} - \sum_{1}^{n} \frac{D_{zf,j}}{D_0} - \sum_{1}^{z} a_j \tag{17}$$

The heat rate is calculated using the below equation

$$\begin{aligned} \text{HR} = \frac{D_0}{P_e} \cdot \big[& (h_0 - h_{\text{fw}}) + \alpha_{\text{crh}} \times (h_{\text{hrh}} - h_{\text{crh}}) \\ & + \alpha_{\text{rhsp}} \times (h_{\text{hrh}} - h_{\text{rhsp}}) + \alpha_{\text{shsp}} \times (h_0 - h_{\text{shsp}}) \big] \end{aligned} \tag{18}$$

5 Application

5.1 Object Introduction. This measurement method was applied to a 660 MW generation unit in China. Mathworks Matlab®(2012 a) is employed for modeling and simulation in this paper. The pressure of superheated steam is 16.7 MPa, the temperatures of the superheated steam and reheated steam are 560 °C, and the principle diagram of the regenerative system is shown in Fig. 3, where HPH stands for high-pressure heater, LPH stands for low-pressure heater, HP stands for high-pressure cylinder, IP stands for intermediate-pressure cylinder, and LP stands for low-pressure cylinder.

5.2 Parameter Values. As previously mentioned, the parameters ε_j, β_j, θ_j, ω_j, and η_{LP} in the regenerative model should be determined using the expert database before calculating the heat rate.

Here, we substitute the parameter β_7 by the pressure loss of the extraction pipe as an example. No pressure sensor is installed at either end of the extraction pipes. Thus, the β_7 cannot be defined using the historical data. The β_7 is set to a constant 5% in the design data. Therefore, the coefficient must be defined using the data from the turbine performance test. The data are shown in Fig. 4. Equation (19) shows the relationship between the coefficient and the turbine output power

$$\beta_7 = -4.9 \times 10^{-9} Pe + 4.72 \tag{19}$$

The other parameters are determined by fitting the equation of the above method; the coefficients of the functions for each parameter are shown in Tables 1–4.

5.3 Heat Rate Calculation. When main steam, reheat steam, and turbine output power are measured, the regenerative system condition can be calculated using Eqs. (2)–(18) so that the heat rate can be calculated using the model.

In the actual application, to make full use of the measured data, when the measured data are correct, the measured data are put into the calculation priority. When the measured data are proved untrustworthy, which means the difference between measured data and calculated data exceeds the set threshold or the measurement data is not logical, the results of model calculations are used.

The value of parameters used in this paper is shown in Table 5. In Table 5, "-" indicates that the parameter is not measured, "*" indicates that the pressure of the extraction is calculated using the outlet temperature of the DEA, and "**" indicates that the extractions of the #7 and #8 heaters are wet steam. The enthalpy of the

Table 1 Equations for parameters ε (equation type $Y = (a \times Pe) + b$)

Parameter	$a \times 10^7$ (1/kW)	b
$\varepsilon 0$	1.82	0.187
$\varepsilon 1$	0.49	0.705
$\varepsilon 2$	−0.304	0.571
$\varepsilon 3$	0.842	0.478
$\varepsilon 4$	−0.214	0.616
$\varepsilon 5$	−0.342	0.541
$\varepsilon 6$	0.402	0.381
$\varepsilon 7$	−0.578	0.300
$\varepsilon 8$	0.934	0.466
εc	−0.671	0.433

Table 2 Equations for parameters θ and ω (equation type: $Y = (a \times Pe) + b$)

Parameter (°C)	$a \times 10^7$ (°C/kW)	b (°C)
$\theta 1$	68	−5.54
$\omega 1$	220	−7.74
$\theta 2$	88	−7.90
$\omega 2$	153	−1.95
$\theta 3$	66	−5.38
$\omega 3$	327	−11.64
$\theta 5$	89	−4.44
$\omega 5$	199	2.07
$\theta 6$	19	−0.63
$\omega 6$	97	12.6
$\theta 7$	76	−2.54
$\omega 7$	270	8.00
$\theta 8$	42	−2.05
$\omega 8$	216	11.00

Table 3 Equations for parameters β (equation type: $Y = (a \times Pe) + b$)

Parameter (%)	$a \times 10^7$ (%/kW)	B (%)
$\beta 1$	−53	5.81
$\beta 2$	−28	4.61
$\beta 3$	−15	4.02
$\beta 4$	−46	8.64
$\beta 5$	−57	8.68
$\beta 6$	−29	5.19
$\beta 7$	−49	4.72
$\beta 8$	−63	11.10

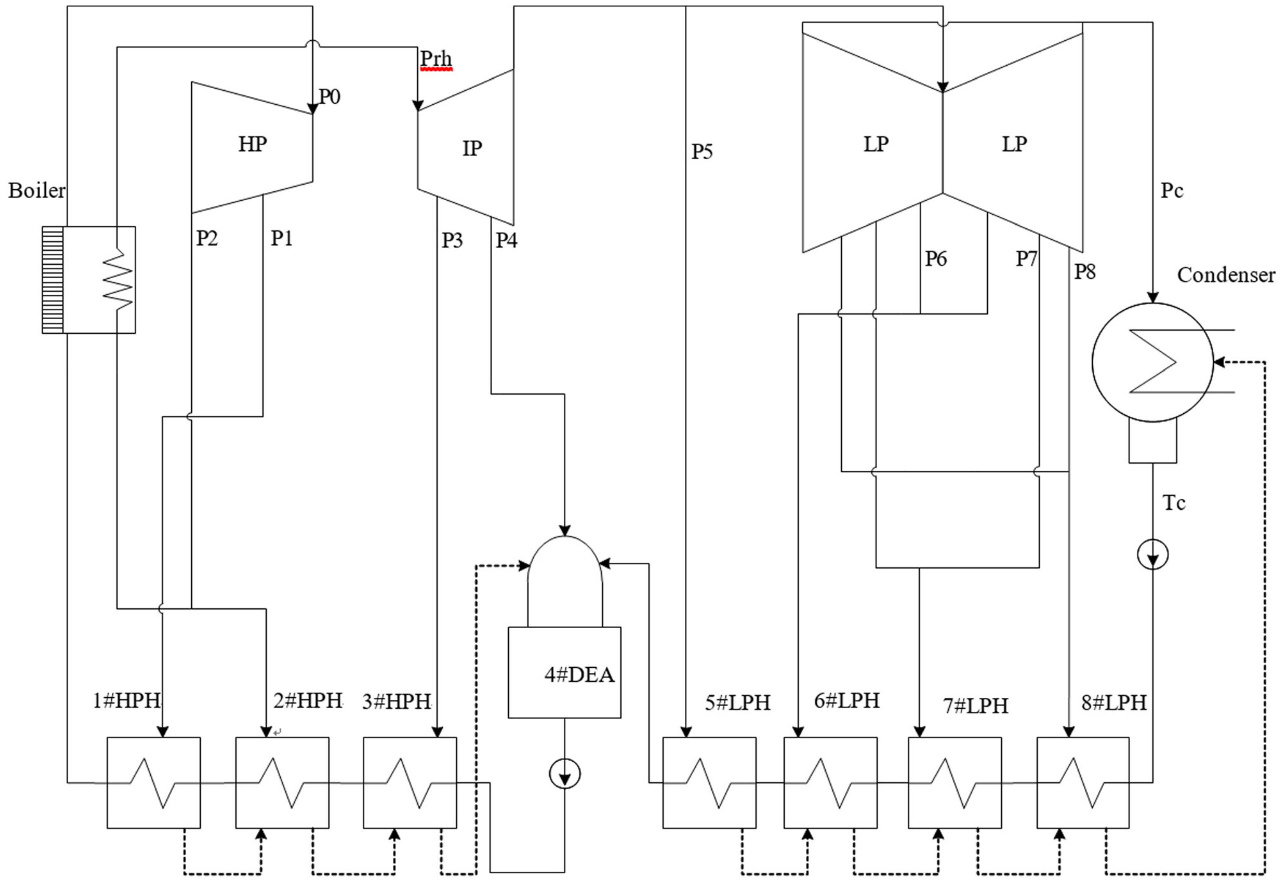

Fig. 3 The principle diagram of the regenerative system of the generation unit

extractions should be calculated using the steam dryness. The dryness of the #7 and #8 extractions is assumed to be 0.99 and 0.95, respectively.

As shown in Table 5, most calculated values are close to the measured values. However, the #5 extraction pressure, #6 extraction pressure, and #6 TTD have abnormal values.

The measured #5 extraction pressure is 0.34 MPa, whereas the model-calculated pressure is 0.433 MPa. According to the turbine design data, when the load is 615 MW, the design data show that the #5 extraction pressure should be 0.458 MPa, so the measured result is inaccurate. As a result, we substitute 0.433 MPa for the #5 extraction pressure in the heat rate calculation. The #6 extraction pressure is in an identical case. The calculated pressure using the model is closer to the turbine operation condition. Because the TTD of the #6 low-pressure heater should not be less than 0 °C, the calculated value 0.5 °C using the model is applied in the heat rate calculation.

We substitute the parameter values in Tables 1–4 into Eqs. (2)–(18), the heat rate of the turbine in this load is called 8074 kJ/kW h.

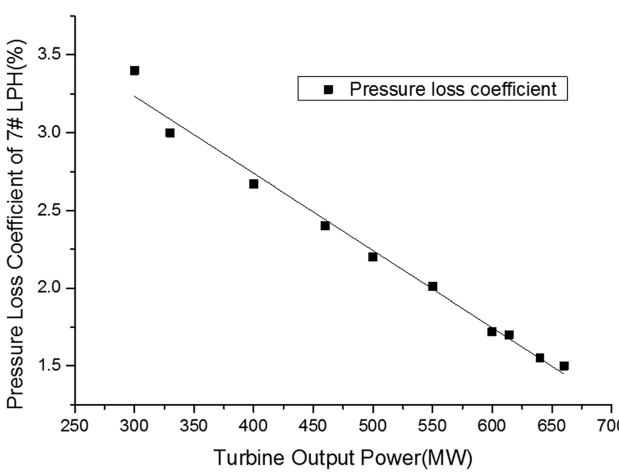

Fig. 4 The fitting of the pressure loss coefficient of the #7 LPH

5.4 Results and Discussion.

Figure 5 shows the monitoring results of the generation unit from 0:00 Aug. 29, 2013 to 0:00 Aug. 30, 2013. Figure 6 shows the comparison among the measured results, calculated results, turbine performance test results, and design data.

As observed from Fig. 5, both measured and calculated heat-rate-monitoring results are correctly related to the change in load,

Table 4 Equations for parameter η (equation type: $Y = (a \times Pe^2) + (b \times Pe) + c$)

Parameter (%)	$a \times 10^{14}$ (%/kW^2)	$b \times 10^7$ (%/kW)	C (%)
$\eta0\cdot\eta1$	94.69	−6.3489	79.41
$\eta2$	3.241	−0.04940	97.12
$\eta3$	3.610	−0.1298	71.96
$\eta4$	5.241	0.02414	94.56
$\eta5$	−39.49	4.997	76.52
$\eta6$	64.72	−3.559	90.72
$\eta7$	46.06	−2.758	86.06
$\eta8$	23.80	−0.4746	78.35
η_{LP}	−32.67	5.295	66.09

Table 5 Value of parameters

	Parameter	Value measured	Value calculated	Error	Value applied in calculation	State
Main steam	Pressure (MPa)	16.79	–	–	16.79	–
	Temperature (°C)	537.41	–	–	537.41	
Reheat steam	Pressure (MPa)	3.48	–	–	3.48	–
	Temperature (°C)	533.49	–	–	533.49	–
Power	Generator power (MW)	614.66	–	–	614.66	–
	Pump consumption power (MW)	22.17	–	–	22.17	–
#1 HPH	Extraction pressure (MPa)	5.02	5.02	0.10%	5.02	Normal
	Extraction temperature (°C)	370	372.3	0.62%	370	Normal
	Inlet pressure (MPa)	–	5.02	–	5.02	Normal
	#1 TTD (°C)	−1.53	−1.37	0.16 °C	1.53	Normal
	#1 DCA (°C)	5.77	5.78	0.01 °C	5.77	Normal
#2 HPH	Extraction pressure (MPa)	3.63	3.69	%	3.63	Normal
	Extraction temperature (°C)	325.2	323.57	−0.50%	325.2	Normal
	Inlet pressure (MPa)	–	3.60*	–	3.6	Normal
	#2 TTD (°C)	−2.53	−2.5	0.03 °C	−2.53	Normal
	#2 DCA (°C)	6.87	7.45	0.58 °C	6.87	Normal
#3 HPH	Extraction pressure (MPa)	2.01	2.04	1.40%	2.01	Normal
	Extraction temperature (°C)	459.52	464.6	1.11%	459.52	Normal
	Inlet pressure (MPa)	–	1.99	–	1.99	Normal
	#3 TTD (°C)	−0.41	−1.32	−0.91 °C	−0.41	Normal
	#3 DCA (°C)	7.43	8.46	1.03 °C	7.43	Normal
#4 DEA	Extraction pressure (MPa)	1.066*	1.064	0	1.066	Normal
	Extraction temperature (°C)	372.54	364.64	−2.12%	372.54	Normal
	Inlet pressure (MPa)	–	1.09	–	1.09	Normal
#5 LPH	Extraction pressure (MPa)	0.34	0.433	21.50%	0.433	Abnormal
	Extraction temperature (°C)	264.5	259.5	−1.89%	264.5	Normal
	Inlet pressure (MPa)	–	0.415	–	0.415	Normal
	#5 TTD (°C)	2.44	1.03	−1.41 °C	2.44	Normal
	#5 DCA (°C)	–	14.3	–	14.3	Normal
#6 LPH	Extraction pressure (MPa)	0.1	0.116	13.90%	0.116	Abnormal
	Extraction temperature (°C)	126.8	129.38	2.03%	126.8	Normal
	Inlet pressure (MPa)	–	0.11	–	0.11	Normal
	#6 TTD (°C)	−1.37	0.53	0.87 °C	0.53	Abnormal
	#6 DCA (°C)	–	18.6	–	18.6	Normal
#7 LPH	Extraction pressure (MPa)	–	0.061	–	0.061	Normal
	Extraction temperature (°C)		86.14		86.14**	Normal
	Inlet pressure (MPa)	–	0.0605	–	0.0605	Normal
	#7 TTD (°C)	–	0.9	–	0.9	Normal
	#7 DCA (°C)	–	24.2	–	24.2	Normal
#8 LPH	Extraction pressure (MPa)	–	0.023	–	0.023	Normal
	Extraction temperature (°C)	–	63.11	–	63.11**	Normal
	Inlet pressure (MPa)	–	0.0225	–	0.0227	Normal
	#8 TTD (°C)	–	0.12	–	0.12	Normal
	#8 DCA (°C)	–	23	–	23	Normal

i.e., when the load decreases, the heat rate increases. However, the stability of the results of the SIS is poor because even under the same load, the measured heat rate of the SIS system shows a deviation up to 300 kJ. The standard deviation of the SIS measurement results is 43.3 kJ/kWh, whereas the standard deviation of the calculated result of this method is 12.2 kJ/kW h. The comparison of the standard deviation shows that the calculated result is steadier.

As observed from Fig. 6, this method provides higher heat rate than the turbine performance test, and the heat rate result of the SIS is lower than the result of the turbine performance test. The monitor results were acquired in summer (August 2013, when the circulation water temperature was over 25 °C), and the turbine performance test data were obtained in winter (January 2013, when the circulation water temperature was below 15 °C). This turbine performance test was carried out just after the overhauling of the 660 MW unit. In August 2013, the unit has been operating for several months since the latest overhaul, so that the heat rate should be higher than the turbine performance test. Under low loads, the heat rate measured using the SIS increased faster, which confirms the theory that the flow measurement is inaccurate when it deviates from the calibration conditions. However, the slopes among the results of this method, design data, and turbine performance test results are consistent under low loads.

The measurement can be verified using this method. Table 5 shows that the extraction pressures of the #5 and #6 LPH and the TTD of the #6 LPH are not adopted because the on-site analysis founded zero drift in these sensors. This method is proved to be able to measure the heat rate with functions of fault tolerance and data validation, it could also be used for heat rate forecasting.

6 Conclusions

A new model-based approach to monitor the steam turbine heat rate is developed in this paper. A regenerative model to complete the heat rate calculation is described in detail. The superheat steam flow is calculated according to the output power of the turbine generation instead of the flow of feed water. Since the measurement of the output power is more reliable and accurate than that of the flow of feed water, the heat rate calculated by this approach would be more stable and accurate. The historical operating parameters, the design data, and the thermal performance test results of the steam turbine are used to establish an expert

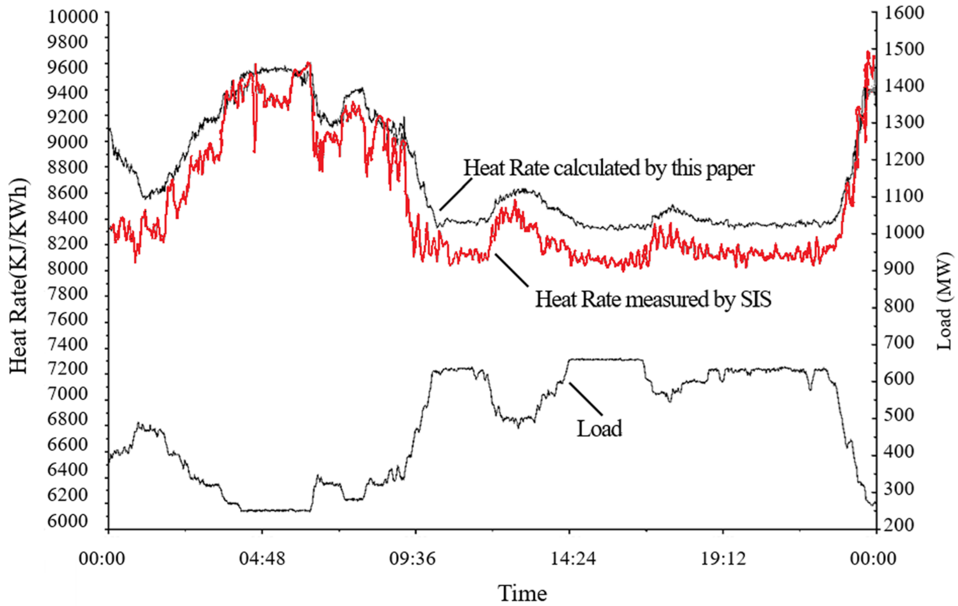

Fig. 5 Heat rate monitor results

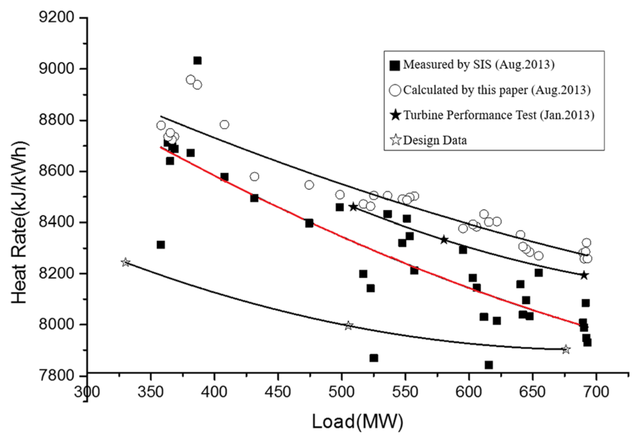

Fig. 6 Comparison among different heat rate results

knowledge database for verifying the online collected parameters. The monitoring results from a 660 MW generation unit in China prove that the presented method is more stable and accurate than the traditional monitoring method that is based on the feed water flow measurement. This model-based approach is proved to be able to measure the heat rate with functions of fault tolerance and data validation. It also could be used for turbine heat rate forecasting. The function of data validation and feasibility of this approach would be checked in more generation units in the future.

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Nomenclature

A = area, m^3
D = flow, kg/h
DCA = drain cooler approach difference, °C
h = specific enthalpy, kJ/kg
HR = heat rate, kJ/kW h
P = pressure, Pa
Pe = power, kW
Q = transferred heat, J/s
T = temperature, °C
TTD = thermal temperature difference, °C
α = steam coefficient
β = calculated pressure loss of the extraction pipe, %
ε = calculated pressure ration between import and export of the stage
η = efficiency, %
θ = calculated thermal temperature difference, °C
ρ = density, ton/m^3
ω = calculated drain cooler approach difference, °C

Subscripts

c = exhaust steam
crh = cold reheat
fw = feed water
g = generator
hrh = hot reheat
i = inlet
j = stage
LP = low-pressure cylinder
m = mechanical transmission
n = number of the shaft seal leakages
o = outlet
rhsp = spray desuperheating for reheat steam
shsp = spray desuperheating for superheat steam
sj = drain
z = number of the stages
zf = shaft seal leakage

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