Monitoring of Steam Plants

OTAKAR JONAS, *Jonas, Inc.*

This article reviews the current state of monitoring water and steam chemistry, scale and deposits, and corrosion in steam plants. It is applicable to fossil fuel utility and industrial, and nuclear cycles. All water chemistry and corrosion problems can be monitored in the field or simulated in the laboratory. A combination of the monitoring and thermodynamic and corrosion modeling can prevent most of the problems and help determine the root causes and selection of engineering solutions after the problems occur.

The cost of corrosion and scale of steam cycle components in all types of cycles is still very high.[1-3] Recent studies determined that the total cost of corrosion in the U.S. is $276 billion/year, including the $6.9-billion/year cost to electric utilities.[3] Detailed statistics for forced outages and deratings for individual system components are available from the North American Electric Reliability Council (NERC).[4] The main cost is for the replacement power or lost production; it is ~10 times higher than the cost of repairs. Scale and deposits often reduce steam-generating capacity and thermodynamic efficiency.[5-6] There are also safety issues to consider, such as stress corrosion of turbine blade attachments, deaerator cracking, and flow-accelerated corrosion of piping.[7]

Sufficient knowledge exists to prevent most of the above problems, and there are monitoring methods for their early detection.[8,9] The best preventive measures include a design review of the steam cycle and cycle components (including a review of material selection and water chemistry), monitoring during commissioning and early operation of the system, and a water chemistry and corrosion audit after 1 to 5 years of operation.[9]

Water and Steam Chemistry Monitoring

Water and steam chemistry guidelines for all types of cycles have been developed and verified,[10-15] and the sampling and monitoring practices have been established.[16-17] Figure 1 shows an example of the monitoring scheme for a fossil utility drum boiler cycle on phosphate boiler water treatment. It shows the monitoring locations and gives "core parameters," which are parameters that must be monitored during normal operation. Today, most of these parameters can be monitored by online instrumentation. Online instrumentation is more practical than grab-sample analysis because there are no chemists in most steam plants, and the plant operators are responsible for water chemistry control. Continuous analytical instruments can easily be incorporated into the modern digital control systems—including alarms in the control room. For troubleshooting, additional parameters—such as chloride, sulfate, and total organic carbon—are determined by grab-sample analysis.

An expert system, such as the EPRI ChemExpert‡,[12] advances the above water chemistry control by identifying the problems that cause water chemistry upsets and determining corrective actions and the consequences and cost of the upset.

OPERATOR ACTIONS

For water chemistry monitoring to be effective in preventing scale buildup and corrosion, there needs to

‡Trade name.

FIGURE 1

Preheat Steam

	Parameter	Sample	N	1	2	3
CR	Sodium, ppb	C	≤3	>3 ≤6	>6 ≤12	>12
CR	Cation conductivity, µS/cm^(A)	C	<0.15	>0.15 ≤0.25	>0.25 ≤0.45	>0.45

Air Removal System Exhaust

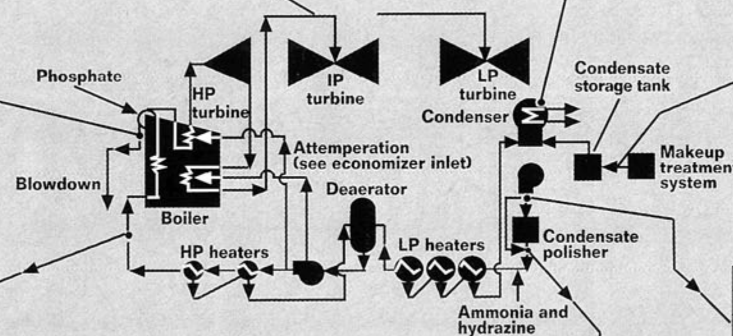
Parameter	Sample	N	1
Air in-leakage acfm/100 mWo	D	≤1	>1

Boiler Water (Blowdown or Downcomer)

	Parameter	Sample	N	1	2	3	Immediate Shutdown
	Silica	C or S	(B)	(B)	(B)	(B)	—
CR	pH^(A)	C	(C)	—	—	—	<8
	Specific conductivity^(D)	C	—	—	—	—	—
	Phosphate	C or S	(C)	—	—	—	—
	Sodium/phosphate ratio	D	(F)	—	—	—	—

Makeup Treatment System Efficient^(D)

Parameter	Sample	N
Silica, ppb	C	≤10
Specific conductivity, µS/cm^(A)	C	≤0.1



Economizer Inlet and Attemporation Water

	Parameter	Sample	N	1	2	3
CR	pH^(A) — All ferrous metallurgy	C	9.2-9.5	<9.2 >9.6	—	—
CR	pH^(A) — Mixed Fe-Cu metallurgy	C	8.8-9.2	<8.8 >9.2	—	—
CR	Specific conductivity^(A)	C	Consistent with pH			
CR	Cation conductivity, µS/cm^(A)	C	≤0.2	>0.2	>0.35	>0.65
	Iron, ppb	W	≤5	>5	—	—
	Copper, ppb	W	≤2	>2	—	—
CR	Oxygen, ppb	C	≤10	>10 ≤15	>15 ≤20	>20

Condensate Polisher Effluent (if applicable)

	Parameter	Sample	N	1	2	3
CR	Sodium, ppb	C	≤3	>3 ≤6	>6 ≤12	>12
CR	Cation conductivity, µS/cm^(A)	C	≤0.2	>0.2	—	—

Condensate Pump Discharge

	Parameter	Sample		N	1	2	3
CR	Sodium, ppb	Plants with polisher	C	≤6	>6	—	—
CR	Sodium, ppb	Plants without polisher	C	≤3	>3	>6	>12
CR	Cation conductivity, µS/cm^(A)	Plants with polisher	C	≤0.3	>0.3	—	—
CR	Cation conductivity, µS/cm^(A)	Plants without polisher	C	≤0.2	>0.2 ≤0.35	>0.35 ≤0.65	>0.65
	Total organic carbons, ppb		W	<200	>200	—	—
	Oxygen, ppb		C or S	≤20	>20 <40	>40	—

Maximum Annual Exposure to Contaminant Conditions

Targets	Cumulative Hours per Year — Base Lead	Cycling
N (normal)	—	—
1 (action Level 1)	336 (2 weeks)	672 (2 weeks)
2 (action Level 2)	48 (2 days)	95 (4 days)
3 (action Level 3)	8	15
Immediate shutdown	1	2

Legend

Sample Frequency	Target Values
C = continuous	N = National
S = grab, once per shift	1 = Action Level 1
D = grab, once per day	2 = Action Level 2
W = grab, once per week	3 = Action Level 3

Footnotes

(A) = Conductivity and pH measured at 25°C

(B) = See curves of maximum allowable concentration vs pressure

(C) = Must be determined

(D) = Target values may be adjusted to reflect capabilities of installed equipment

(E) = Up to 1 ppm free NaOH

Sample and Chemical Feed Identification

CR = Record and alarm in control room

↦ = Continuous sample

→| = Chemical feed

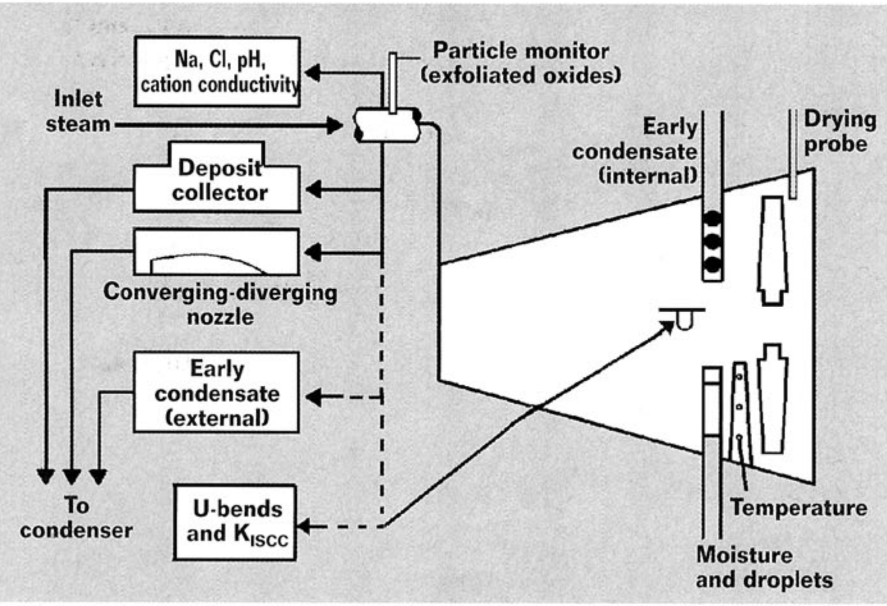
Sampling and monitoring of a utility drum boiler unit on phosphate boiler water treatment—core parameters.[11] Copyright © 2003. Electric Power Research Institute. TR-103665. *Cycle Chemistry Guidelines for Fossil Plants: Phosphate Treatment for Drum Units.* Reprinted with permission.

TABLE 1

MONITORING RELATED TO WATER AND STEAM CHEMISTRY, SCALE, AND DEPOSITS

Device	Applications	Monitoring Results
Steam turbine deposit collector/simulator	High-pressure (HP), intermediate-pressure (IP), and low-pressure (LP) turbines	Deposit composition, morphology, and rate of deposition vs operation
Converging-diverging nozzle for LP turbines	Fossil and nuclear LP turbines	Quantity and types of impurities depositing on LP turbine blades and corrosiveness of the environment
Converging nozzle for HP turbines	Simulates HP turbine deposition	Types of impurities depositing on HP turbine blades
Drying probe for wet steam stages	Simulates moisture drying on hot surfaces in LP turbines	Deposits of low-volatility impurities in LP turbines are collected
Boiler carryover monitors	Boilers/turbines	Mechanical carryover
Early condensate samplers	LP turbines, boilers, condensers	Chemistry of water droplets formed in the final stages of the LP turbine, etc.
Particle flow monitor for exfoliated oxides	Piping, turbines; also used to monitor effectiveness of steam blow and foreign object damage	Number and size distribution of oxide particles in superheated and reheated steam
Biofouling monitor	Condensers, cooling towers	Detection of biofouling, collection of organic matter
In situ pH and corrosion potential	Piping, heat exchangers, boilers	Susceptibility to general and localized corrosion
Heat flux gauge	Boiler tubes	Value of local heat flux, type of boiling, potential for impurity concentration
Chordal thermocouples	Boiler tubes	Boiler tube temperature vs scale
Rotor position and thrust-bearing wear	Deposit buildup in turbines	Damage to thrust bearing caused by deposit accumulation on blades
Turbine first-stage pressure	Deposits and erosion in turbines	Degree of deposition or erosion of control stage

FIGURE 2



Monitoring of LP turbine steam and condensate chemistry and corrosion.

be an approved company policy that provides for timely corrective actions, an operator water chemistry manual, and operator and chemist training.

SAMPLING

Sampling can be a source of up to 1,000% errors in determining the values of control parameters.[16] The errors usually are caused by nonisokinetic sample withdrawal and scale and deposit buildup in the sample tubing because of a sluggish flow. For steam and feedwater, samples should be withdrawn using an isokinetic sampling nozzle.[16-17] The liquid sample flow velocity should correspond to a turbulent flow.

QUALITY CONTROL

Quality control of sampling and analysis is essential to avoid often expensive and inappropriate corrective actions based on incorrect water chemistry data.

TABLE 2

SUMMARY OF DEVICES FOR FIELD CORROSION MONITORING

Device	Applications	Monitoring Results
Corrosion product monitor	Feedwater systems including feedwater heaters	Quantitative determination of corrosion product transport
Erosion-corrosion (flow-accelerated corrosion)	Piping components	Thinning rate for materials of concern in the specific suspected areas of piping
U-bend and double U-bend specimens	LP turbines, piping, feedwater heaters, condensers, boilers	Detects general corrosion, pitting, and SCC; double U-bends simulate crevice and galvanic effects
Fracture mechanics specimens	LP turbine disks and rotors, piping, headers, deaerators	Stress corrosion and CF crack growth rate and crack incubation times
Heat exchanger or condenser test tube	Condensers, feedwater heaters, and other heat exchangers; installed within the circuit	Accumulation of scale and corrosion pertinent to plant-specific conditions
Model crevice	Studies of crevice chemistry and corrosion—heat exchangers, PWR steam generators	Crevice chemistry and corrosion data for specific conditions
Corrosion hydrogen monitor	Boiler tubes, feedwater system, and PWR steam generator corrosion	Detect general corrosion vs load and chemistry; hydrogen damage, caustic gouging in boiler tubes, potential for impurity concentration
Vibration signature	Turbines and pumps—periodic monitoring	Detection of cracks and other distress
Boiler tube leak monitor	Fossil boilers	Early detection and location of a tube leak
Acoustic emission leak detector	Feedwater heaters and other heat exchangers	Early detection of tube leaks
Cavitation monitor	Feedwater piping and pumps	Early detection of cavitation noises
Stress and condition monitoring system	All types of steam cycles and major components	Actual on-line stresses, temperatures, and other conditions; used to determine damaging conditions and residual life
Turbine blade telemetry	LP turbines	Resonant frequencies and alternating stresses

SPECIAL MONITORING TECHNIQUES

Special monitoring techniques are available to supplement normal water chemistry control.[18-22] They help operators observe scale and deposits, composition of moisture droplets and liquid film in two-phase regions, in situ corrosion potential and at-temperature pH, and exfoliation in the superheater and reheater. Table 1 gives a description of these devices.

Figure 2 presents an example of special monitoring applications for steam turbines and shows the installation of several devices.

Corrosion Monitoring

Field corrosion monitoring techniques used in steam-cycle components include direct monitoring of corrosion, exposing coupons and stressed

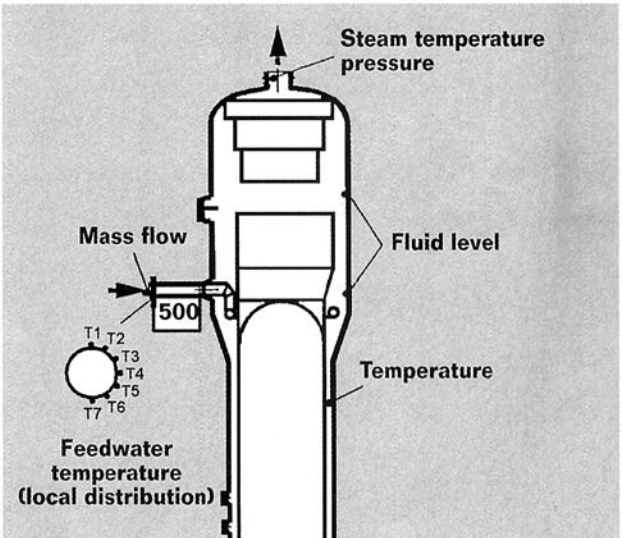


FIGURE 3

Measurement points for monitoring of a pressurized water reactor (PWR) steam generator.

and precracked specimens, and monitoring corrosion hydrogen and corrosion potential, leak detection, and observing vibration changes caused by cracking in turbines and pumps.[18-22] Two factors that are not monitored often enough are thermal stresses in heavy sections, which can lead to low-cycle corrosion fatigue (CF),[23-25] and vibration in rotating machinery, which can lead to high-cycle CF. Inspection and nondestructive testing also are forms of monitoring. Descriptions and application information for these corrosion monitoring methods appear in Table 2.

References 23 and 24 give examples of extensive condition monitoring used in several German PWR nuclear units. There are up to 400 monitoring points per unit covering piping and main components of both primary and secondary cycles. Figure 3 illustrates monitoring of steam generators.[24] Based on the monitored stresses, temperatures, pressures, flows, water levels, valve positions, and water chemistry, one can determine CF, stress corrosion cracking (SCC), and potential and actual damage from flow-accelerated corrosion. The monitoring can discover operating problems, such as leaking valves, which can be quickly corrected. The main benefit is a reduction of downtime for investigation of possible problems; the state of the equipment, its stress history, and its residual life are readily available. A much smaller version of this monitoring system has been used in the U.S.[25]

References

1. J. Payer, et al., "Economic Effects of Metallic Corrosion in the U.S.," NBS Special Publication 511-2, U.S. Department of Commerce, 1978.

2. O. Jonas, "Cost of Corrosion and Scale in Electric Utilities," EPRI Symposium on Fossil Utility Water Chemistry (Palo Alto, CA: EPRI, 1985).

3. B. Syrett, et al., "Cost of Corrosion in the Electric Power Industry," MP 41, 3 (2002).

4. pc-GAR (Generating Availability Report, Statistical Data 1982-2000), North American Electric Reliability Council, NERC, 2002.

5. O. Jonas, "Steam Turbine Efficiency and Corrosion: Effects of Surface Finish, Deposits, and Moisture," Report 1003997 (Palo Alto, CA: EPRI, 2001).

6. O. Jonas, et al., "Copper Deposition and MW Loss Problem Solutions," 57th International Water Conference (Pittsburgh, PA: October 1996).

7. O. Jonas, "Safety Issues in Fossil Utility and Industrial Steam Systems," MP 40, 5 (2001).

8. State of Knowledge: Low Temperature Corrosion in Fossil Utilities (Palo Alto, CA: EPRI) (to be published in 2003).

9. O. Jonas, J. Mancini, "Steam Turbine Problems and Their Field Monitoring," MP 40, 4 (2001).

10. "Interim Consensus Guidelines on Fossil Plant Cycle Chemistry," CS-4629 (Palo Alto, CA: EPRI, 1986).

11. "Cycle Chemistry Guidelines for Fossil Plants: Phosphate Treatment for Drum Units," TR-103665 (Palo Alto, CA: EPRI, 1994).

12. O. Jonas, L. Machemer, B. Dooley, "EPRI ChemExpert: Cycle Chemistry Advisor for Fossil Power Plants," EPRI—Sixth International Conference on Cycle Chemistry (Ohio: 2000).

13. "PWR Secondary Water Chemistry Guidelines, Revision 2," NP-6239 (Palo Alto, CA: EPRI, 1988).

14. "BWR Water Chemistry Guidelines," NP-3589-SR-LD (Palo Alto, CA: EPRI, 1985).

15. "Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers" (New York, NY: ASME, 1994).

16. O. Jonas, "Development of a Steam Sampling System," TR-1000196 (Palo Alto, CA: EPRI, 1991).

17. ASTM D1066, "Standard Practice for Sampling Steam" (West Conshohocken, PA: ASTM).

18. O. Jonas, "Steam Generation," Corrosion Tests and Standards (West Conshohocken, PA: ASTM, 1995).

19. O. Jonas, "Diagnostic Monitoring—An Overview," Power 1 (1992).

20. "Corrosion Testing and Evaluation," in Metals Handbook, 9th ed., Vol. 12, Corrosion (Metals Park, OH: ASM International, 1987).

21. O. Jonas, "New Continuous In-Line Method for Monitoring of Solid Particles and Results of Field Testing," CS-4683, Proceedings of Solid-Particle Erosion of Utility Steam Turbines: 1985 Workshop (Palo Alto, CA: EPRI, 1986).

22. O. Jonas, et al., "Evaluation and Application of a New Dissolved Hydrogen Analyzer," Paper IWC-85-27, 46th International Water Conference (Pittsburgh, PA: November 1985).

23. O. Jonas, J. Bartonicek, F. Schoeckle, "Piping Integrity Monitoring System for GKN PWRs," ASME 1995 Pressure Vessel and Piping Conference (Honolulu, HA: 1995).

24. J. Bartonicek, O. Jonas, F. Schoeckle, "Quantification of the Safety Status of PWR Steam Generators," ASME Pressure Vessel and Piping Conference (1996).

25. P. Riccardella, et al., "On-line Transient Monitor Determines Fatigue Damage," Power Engineering 11 (1987).

OTAKAR JONAS is President of Jonas, Inc., 1113 Faun Road, Wilmington, DE 19803-3314. He consults in the areas of steam cycle corrosion and water chemistry, failure analysis, troubleshooting, and research and development. He has more than 35 years of corrosion experience, including 7 years as an assistant professor, 16 years in industry, and 20 years as a consultant. He has a Ph.D. in power engineering and is a professional engineer. He currently serves on the *MP* Editorial Advisory Board. MP