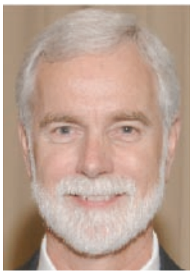
Steam-plant workshop focuses owner/operators on best practices for managing water chemistry, improving O&M

The steam-plant workshop held annually in the fall to address O&M challenges at gas-turbine-based cogeneration and combined-cycle facilities—with many lessons applicable to conventional fossil-fired stations as well—is gaining stature and appears well on its way to becoming one of the industry's "must-attend" meetings.

It is conducted by the HRSG User's Group, an organization best known for its spring conference and exhibition dedicated to the design, operation, and maintenance of heat-recovery steam generators. Last fall's workshop, held in Las Vegas, was arranged as a two day-long meetings by HRSG User's Group Chairman Robert Anderson, formerly of Progress Energy and now principal, Competitive Power Resources Corp, Palmetto, Fla (anderson@competitivepower.us).

First day's program focused on "Managing the Chemistry Program," the second on "Improving Steam-Plant O&M." Nine authorities presented tutorials in their respective fields of expertise. As with other HRSG User's Group events, all delegates—experts and non-experts alike—had ample opportunity for questions, discussion, and comment. More than 200 power professionals attended the workshop, a 50% increase over 2004.

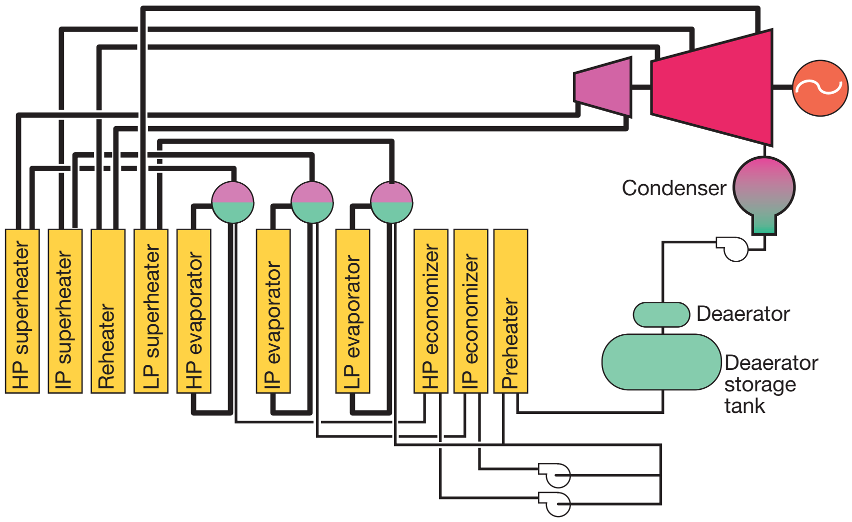

Anderson


Bignold

The constant of chemistry

Within the steam-plant community, interest in water chemistry is never-ending. The HRSG User's Group took a different tack than most meetings on the subject by focusing on the *management* of a plant's chemistry program, rather than on the chemistry itself.

Geoff Bignold, founder, GJB Chemistry for Power Ltd, Surrey, UK, led off these discussions with an overview of the best options for chemistry data collection and analysis. Bignold reviewed how to make decisions about what parameters to measure, where to measure them, and what equipment to use (Fig 1). He reminded the group that the main objectives of online monitoring are to provide reassurance that operation is within targets and to alert operators when targets are not being met.



1. Arrangement of heat-transfer surfaces and steam and water circuits offer roadmap for monitoring chemistry parameters

What to measure

Direct conductivity, Bignold said, can be a useful measurement for controlling automated feedwater and boiler-water chemical-feed systems. But caution was suggested. Reason is that instrumentation cannot discriminate between the conductivity contributed intentionally by treatment chemicals and that contributed by undesirable contaminants. Thus, if alkali for boiler-water treatment were controlled solely on the basis of direct conductivity, there is a risk that the dosing rate would be reduced during periods of contamination—the opposite of what is needed.

Cation conductivity can be superior to direct conductivity for detecting water-borne contaminants like chlorides and sulfates. However, Bignold warned that cation conductivity readings are affected by the presence of CO_2. This can lead to high readings during startup that may not be related to dangerous contamination but still delay operators in rolling the steam turbine (ST). Degassing of the sample can be effective for removing CO_2, thereby allowing ST startup to proceed if conductivity drops within acceptable limits.

pH control. Most operators know that good pH control is critical for preventing the dissolution of metal oxides, deposit formation, and corrosion. Those attending Bignold's presentation learned that measurement of pH in the very pure feedwater and boiler water most plants strive for can be prone to error unless instruments specifically designed for dilute samples are specified.

DO. Like pH, the importance of controlling dissolved oxygen is well-known. A subtle pointer offered by Bignold: A base-load facility may be able to get by measuring DO in feedwater at only one location (and manually switching the instrument to other points in the condensate system for troubleshooting), but a cycling unit requires multiple full-time sample points for dissolved oxygen.

Silica is a boiler-water contaminant that will deposit in the ST and adversely impact its performance if allowed to carry over in the steam. Note that silica's volatility increases with boiler pressure. Measuring silica in boiler water and establishing safe limits by correlating measurements and adjusting for boiler pressure was recommended. Online silica monitors are used at many plants, but periodic manual analysis is sufficient for facilities with stable operations, Bignold asserted.

Phosphate is a popular treatment additive for many drum boilers and accurate measurement of its concentration is critical to proper chemistry control. But success of the treatment program also depends on the knowledge of operators regarding the behavior of phosphate in your boiler, especially that it can be lost to the system because of blowdown and "hideout."

Recall that phosphate solubility decreases as pressure and temperature increase; some may even drop out of solution as pressure rises (hideout). Thus instrument readings will be lower than actual. The hidden phosphate returns when pressure drops (so-called "hideout return").

Failure to understand this phenomenon and follow procedures to optimize phosphate control can drive operators crazy in high-pressure (HP) plants subject to frequent load swings. Online analyzers are of considerable value at plants subject to hideout. But for low-pressure (LP) plants and those with constant load profiles, periodic manual analysis is sufficient.

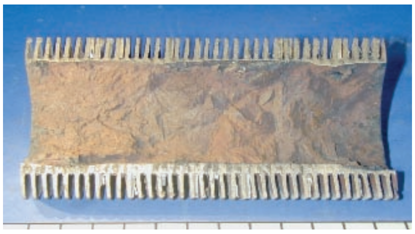
Measurement of sodium contamination in steam is convenient for monitoring carryover, continued Bignold, and measurement of sodium in condensate is particularly effective for detecting condenser leaks. But keep in mind that sodium detection electrodes lose their sensitivity in the very pure water required for HP boilers. They require a constant high-pH environment to ensure accurate readings over time.

Other considerations. The transients associated with startup and shutdown events create additional challenges in effective management of plant chemistry. It is common for sample-line flow rates to change as pressures increase and decrease and these require adjustment.

Likewise, sample-temperature changes occur during transients. It is important that plants experiencing frequent cycling use on-line monitoring instruments equipped with automatic temperature compensation and maintain this feature in good working order. Sampling errors also can result from oxygen reaction with sample line walls, release of metal oxides from sample lines, and changes in drum level.

Shulder

2. Flow-accelerated corrosion can occur in almost all HRSG piping that contains water and water/steam mixtures



3. Under-deposit corrosion mechanisms include hydrogen damage, phosphate attack, and oxygen pitting

4. Corrosion fatigue is most common in and around economizers, though it also is possible in evaporator sections

What to sample and why

- Condensate. Essential; provides the first indication of a condenser leak.
- Feedwater. Essential; confirms condensate purity and provides information on the control of dosing chemicals within the circuit.
- Drum water. Essential; guides dosing and blowdown.
- Saturated steam. Optional; accuracy may be affected by the presence of water droplets.
- Superheated steam. Optional; high thermal load on sample coolers can adversely impact sample reliability.

Bignold concluded the first session with this advice for powerplant managers:

- Emphasize dependence on the simple, reliable methods for measuring direct conductivity, cation conductivity, and pH.
- Be sure operators have instrumentation that they can trust.
- Monitor properly all parameters for which operational targets are set.

Impacts of cyclic operation

It's no surprise that frequent startups and shutdowns present additional challenges for plant operators. Water-chemistry problems that can be initiated by, or exacerbated by, cycling include flow-accelerated corrosion (FAC, Fig 2), under-deposit corrosion (Fig 3), and corrosion fatigue (Fig 4). Stephen Shulder, chemistry consultant, Constellation Energy Group, shared his experience with delegates on how to minimize such problems by reducing chemistry swings during transients. He stressed that maintaining satisfactory water chemistry demands consistent execution of established procedures.

Shudler then focused on what he considers three of the most important things (from a water-chemistry perspective) plant operations personnel must be sure to do correctly during startup: (1) Avoid air in-leakage; (2) Keep boiler-water quality within spec; and (3) Verify acceptable steam quality before rolling the turbine. He offered the following helpful actions to achieve these goals:

- Blow down sample lines as soon as pressure is available.
- Provide an adequate supply of cooling water to sample coolers.
- Ensure that the sodium analyzer has plenty of fresh buffer.
- Be sure that the pH reference solution is fresh.
- Inspect cation resin columns to make sure they are not depleted.
- Calibrate analyzers.
- Test quality of hotwell and condensate storage water before filling the boiler or initiating startup.
- Verify that a sufficient quantity of demineralized water is available.
- Over-feed amine into condensate during startup.
- Minimize reducing agent (oxygen scavenger) feed at all times.
- Use a solids-based boiler treatment program.
- Verify that the boiler blowdown system is ready for service.
- Bypass the steam turbine until steam quality is within spec.
- Maintain proper water levels in drums.
- Blow down until boiler-water quality is acceptable.
- Pull vacuum as quickly as possible.
- Check for air in-leakage to the condenser and condensate pump suction; repair any leaks identified.

Problems encountered when the guidelines above are not consistently well-executed include the following:

- Low pH in condensate and boiler water.
- Excessive feeding of reducing agent (oxygen scavenger).
- Contamination of condensate.
- Excessive oxygen in condensate and feedwater.
- Inadequate online monitoring capability.
- Decomposition of organic water-treatment chemicals.
- Steam carryover.

The objective of minimizing oxygen-scavenger feed while also avoiding excess oxygen in condensate and feedwater may seem at odds. However, there is good reason to manage both carefully. Oxygen scavengers have been identified as a significant driver of FAC. Even small intermittent feeding of these chemicals can be detrimental to piping and boiler tubing.

If condensate and feedwater purity are on target and free of undesirable contaminants, the level of oxygen that can be tolerated without causing problems is much higher than in years past when ultra-pure water was not available for boilers. Best advice: Don't use oxygen scavengers at all.

Once the plant is online and operating normally, Shulder suggested the following operating goals:

- Quickly bring plant water quality within spec.
- Blow down to remove corrosion products transported to the boiler from the condensate and feedwater systems.
- Flush boiler chemical-feed lines with condensate or demineralized water.
- Monitor the impact of cascading blowdown on intermediate-pressure (IP) boiler chemistry.

Other suggestions made by Shulder to help stabilize your chemistry program:

- Connect the output of online analyzers to the plant's DCS (distributed control system).
- Provide operators with alarms on key chemistry parameters.
- Develop operating specifications for key chemistry parameters along with corrective actions to initiate during excursions.
- Monitor online analyzer performance by taking periodic grab samples.
- Ensure adequate inventory of treatment chemicals.
- Stock a spare injection pump for each chemical.

Many operators relax their focus on water chemistry when the plant is offline. This is a mistake: Serious boiler damage can occur during a short-term wet layup if the proper chemistry is not maintained. Shulder offered these pointers to protect equipment and enhance the chances of a smooth startup:

- Elevate condensate pH.
- Nitrogen blanket all drums as pressure decays.

- Maintain condenser vacuum or supply warm dry air to the steam side of the condenser.
- Close inlet valves on the sample conditioning system.

Long-term layups should be dry, when possible. Follow these steps for best results:

- Drain the condensate system.
- Drain the condenser water side, or maintain cooling-water flow.
- Drain economizers and evaporators while hot, ensure drums are completely dry.
- Keep analyzer probes wet; remove them and store in water or appropriate solutions.

Shulder emphasized several times that management of the plant's chemistry program requires constant vigilance during layup and outages. It is especially important to inspect critical equipment early in an outage so repairs and adjustments to chemistry programs and procedures can be done in timely fashion. Your inspection should include the following:

Pretreatment system. Be sure it is in top condition. The success of your chemistry program depends on high-quality makeup.

Condenser shell side. Check for sludge and signs of corrosion and other damage. Remember that any corrosion products from the condenser eventually wind up in the boiler and you don't want them there.

Steam drums. Make sure steam separators, chemical-feed piping, and blowdown piping are in good condition. Look for evidence of sludge deposits, corrosion, and confirmation of correct water level.

HRSG gas flow path. Check the condition of tube fins, gas baffles, and headers; inspect for evidence of cold-end corrosion.

Steam turbine. Look for evidence of deposition and corrosion.

Tracking iron transport

You may wonder why discussions on managing boiler chemistry have so much to say about external boiler piping and the condenser. Recall that as water is boiled in the HRSG's evaporators, any solids in the water are concentrated as they remain behind. Those that stay dissolved or in suspension are removed via blowdown. But, some form deposits on the internal surfaces of the tubes when temperatures and concentrations are sufficiently high. Chief among these are iron oxides.

Problems can arise when oxides that develop inside the condenser, condensate and feedwater piping, and/or economizers are released and transported by the feedwater into the evaporators. Iron oxide deposits by themselves rarely take the blame for HRSG tube damage. However, as they thicken, an environment increasingly receptive to underdeposit corrosion develops when chloride and sulfate contaminants are present. Eventually, chemical cleaning is required to avoid serious tube damage; it is both bothersome and expensive.

At the workshop, Brad Burns, chemistry program manager, Progress Energy, compared two methods of tracking iron transport—grab sampling and integrated corrosion product (ICP) sampling. Table, p 45, presents the pros and cons of these two methods as well as recent experience.

Burns warned that getting accurate results can be tricky. For example, errors can be introduced when sample flows vary with load or sample flows are split. Some tips offered by Burns to ensure accuracy:

- Use separate sample lines for corrosion-product transport testing. Be aware that cost probably will be an issue.
- Remember that consistent processes are key to successful trending. Write procedures to ensure

consistent sampling, handling, and analysis.
- Sample feedwater pump discharge and evaporator water (or blowdown).

Identify, prevent FAC

Most of the damage mechanisms initiated by a poorly managed chemistry program—such as flow-accelerated corrosion, FAC—can cause significant commercial pain; sometimes they have far more serious consequences. Recall that FAC occurs when the protective oxide layer inside carbon steel pipe or tubing is rapidly dissolved and replaced in a localized area. If undetected, the result can be a sudden, catastrophic failure of the pressure part.

When this occurs inside the HRSG it's just another tube leak (Fig 5). But, in some cases where it has occurred in external piping (Fig 6), people have been killed. Bill Stroman, manager, water chemistry, Primary Energy Holdings LLC, explained to the delegates how FAC is strongly influenced by localized flow velocity, temperature, pH, and the reducing environment created when a residual of oxygen scavenger is maintained.

Most susceptible are components operating at between 200F and 350F; FAC activity peaks between 266F and 302F. In many HRSGs, this means that deaerators, LP drum walls, drum internals, evaporator riser bends, and economizers—as well as IP and HP economizer risers—can suffer damage. Stroman offered the following tips for managing FAC:

- Replace FAC-damaged components with material containing at least 0.1% chromium—even such a small amount of chromium will inhibit FAC attack in a well-designed system.
- Avoid the use of oxygen scavenger if possible; if you can't, minimize its use.
- Maintain a positive oxidizing/reducing potential (ORP) in condensate and feedwater.
- Control pH between 9.4 and 9.6.
- Monitor and trend iron oxide levels in feedwater and drums.
- If a failure occurs, perform a thorough root-cause analysis and implement effective corrective action.

5. FAC in LP evaporator exhibits characteristic teardrop shape

6. Catastrophic failure of feedwater pipe was caused by FAC

Stroman

To identify any FAC damage before a failure occurs, Stroman recommended conducting an ongoing survey to locate suspect components. Periodically inspect for wall thinning, any pipe and tubing bends, tees, etc, operating in the active temperature range for FAC. External ultrasonic NDE (nondestructive examination) was suggested as one method for this work. FAC's distinctive rough appearance sometimes allows it to be seen from inside the tube using a borescope or video probe.

For more background on FAC, access at www.psimedia.info/ccjarchives "FAC and cavitation: Identification, assessment, monitoring, prevention," COMBINED CYCLE Journal, Spring 2004, p 13.

Meeting steam purity specs

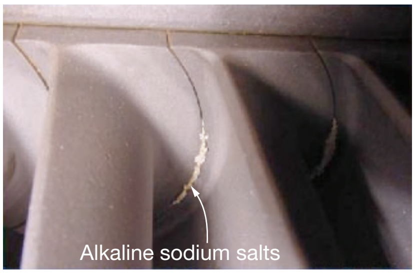
By this point in the meeting no delegate could doubt that effective management of HRSG water chemistry is critical to preventing pressure-part failures. Next, Bignold returned to the podium and showed how the benefits of a well-managed chemistry program extend beyond the HRSG and associated piping.

On the receiving end of steam produced by the HRSG is one of the most expensive and demanding components of a combined-cycle plant—the steam turbine. As with people, the ST's performance and long-term health is largely determined by what it ingests. If turbine steam contains even small quantities of impurities detrimental to the machine, the results can ruin a plant manager's day—possibly his career.

Contaminants enter the superheater and ST in two ways: as vapors or solutes mixed with the steam, or in water droplets "carried over" with the steam if the drum steam separators are not working properly. Bear in mind that dry steam is limited in the amount of solute and contami-

Pros and cons of grab and integrated corrosion product sampling for tracking iron transport

Method	Pro	Con	Experience
Grab sample	1. Relatively simple to obtain samples 2. No special equipment required	1. Difficult to distinguish between particulates and dissolved corrosion products 2. Only *estimates* corrosion at one point in time, at best	1. Sporatic data 2. Difficult to identify any step changes when a process change is made 3. Many samples required to obtain a useful average 4. Spot checks are useless
Integrated corrosion product sampling	Estimates corrosion over a period of time (shows *cumulative* effect)	1. Sampling requires special equipment 2. Analysis can be difficult without the proper analytical equipment	1. Step changes can be seen 2. Considerable time needed to maintain sampler, obtain analysis 3. Even spot checks can yield useful data 4. Acquiring startup data can be difficult if filters overload (you must determine optimum total volumetric throughput)



7. Alkaline sodium salts transported to turbine in droplets of carryover entrained in the steam diffuses out of blade root crevices on the last stage of the IP rotor

Solution diffuses out of crevice and crystals form on open surfaces

8. Least soluble salts collect in hottest regions of the turbine. Here solute diffuses out of crevice and crystals form on open surfaces

nants it can carry. These values are well understood and predictable, so it would take a long time for damaging amounts to deposit in the turbine if reasonable chemistry program management is exercised.

By contrast, carryover can very quickly foul the turbine and superheater because of the large quantities of solutes (Fig 7) and particulates that water droplets are capable of carrying. Droplet carryover is strongly influenced by drum level, design and condition of steam separators, and foaming. It is easy to understand how intermittent steam sampling could miss carryover associated with operating transients.

Bignold told the group what contaminants to track and what damage each can do if allowed to carry over with the steam at levels beyond those specified by the ST manufacturer. He warned that it is critical for operations personnel to consistently meet the steam turbine manufacturer's limits for steam purity. Here are the details:

Inorganic salts (sodium, potassium, chloride, bromide, nitrate, sulfate, phosphate, etc) are soluble in high-pressure steam. However, solubility drops by many orders of magnitude as steam expands. The result is deposition on steel surfaces, with the least soluble salts collecting on the hottest surfaces, and the progressively more soluble salts depositing in the ST at lower and lower pressures (Fig 8). Some of these contaminants only foul the steam path and degrade performance while others cause irreversible and dangerous corrosion (pitting, stress corrosion cracking, and corrosion fatigue). Here are some points to remember:

Particulate oxides (magnetite, hematite, etc) exfoliate from the steam side of superheaters and reheaters. Flakes of oxide can cause damage to turbine valve and blade surfaces. Steam-path parts damaged by "solid particle erosion" eventually require replacement. Control of oxide spalling is generally influenced by plant temperature cycles, although changes in reducing/oxidizing conditions also may be important.

Oxide deposits (copper, as cuprous oxide, and iron oxide) can deposit in HP cylinders and cause performance loss. However, copper is seldom found in combined-cycle plants and performance affects from iron deposition usually are small.

Silica is relatively soluble in high-pressure steam. Deposition occurs in LP turbines when recommended silica limits are exceeded. The deposits are rough and reduce the output and efficiency of the machine. This fouling can be reversed by turbine disassembly and grit blasting.

Adverse impacts of organic contaminants are exacerbated by the presence of formates, acetates, etc. Source materials may be decomposition and oxidation of organic contamination in makeup water or use of organic dosing chemicals—such as amines and oxygen scavengers. Despite high superheat and reheat temperatures, some organic molecules do not break down and oxidize.

If steam contains organic acids without any cations of low volatility, then early condensate can be acidic and aggressive. Pitting corrosion as a precursor to corrosion fatigue and stress corrosion cracking can occur. If alkalis of low volatility (some amines, for example) are present in sufficient quantity, then early condensate will be less of a corrosive threat.

Carbon dioxide increases the conductivity of steam samples after cation exchange, masking the presence of other contaminants. Some turbine manufacturers suggest a relaxation in targets for conductivity after cation exchange if tests reveal that CO_2 dominates rather than other, more corrosive species. Equipment is commercially available for analysis of "degassed" steam samples.

Improving steam-plant O&M

"Successfully managing a powerplant for long-term profitability is all about doing the right things well, at the right time, over and over again," said Chairman Anderson as he opened the meeting on the second day. "This may not sound too glamorous, but significant rewards and satisfaction come to those who can figure out what the right things are, when to do them, and have the leadership skills to get them executed consistently," he continued.

Effective management of your powerplant's chemistry program certainly should be at the top of the facility manager's list of the "right things" as Anderson called them. The second day of the workshop focused on several others.

Optimizing ST, condenser performance

Startups of combined-cycle plants offer the opportunity to damage expensive equipment, burn fuel with no direct compensation, and possibly accrue commercial penalties for missing startup schedules. But they also offer the opportunity to excel for those who can identify the optimum balance between protecting equipment and starting up rapidly, and doing both consistently.

Threlkeld

Robert Threlkeld, plant manager, Tenaska Lindsay Hill and Central Alabama Generating Stations, each a 3 × 1 combined cycle with a nominal rating of 850 MW, shared with attendees some of the things his team has done to improve startup performance and profitability.

It took work to achieve the results desired, but operators now start the steamer in full automatic to get consistent performance right at the manufacturer's stress limits—nailing the numbers as Threlkeld is fond of saying. This makes for more predictable startup durations, saves fuel by reducing overall startup time, and allows use of all available rotor fatigue life without overshoot—the turbine's stress monitor providing constant inputs to startup controls.

One of the challenges the Tenaska team had to overcome to use the automatic startup feature was getting it commissioned. At many plants, the difficult commissioning tasks often are left for the operating crew in the EPC (engineer/procure/construct) contractor's rush to get the plant accepted, get its money, and get gone. Once plant personnel got a handle on the auto-start system and the required interfaces, they still had to overcome the challenges of limiting stresses on the HRSG, changing attitudes, and providing sufficient training.

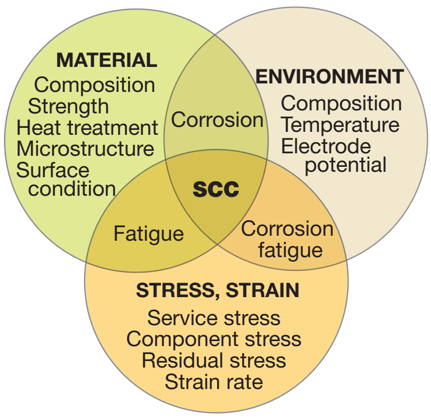
The payback: Cold start time for the Central Alabama ST was reduced by 30%, rotor stress was lowered by one-third, and startup gas consumption dropped by 15%. For more detail on the development of this procedure, refer to "Optimizing a cold steam-turbine startup on one gas turbine" in the Best Practices Awards section, p 16.

Another challenge tackled by personnel at Central Alabama as well as Lindsay Hill was optimization of condenser backpressure. Some of the obstacles overcome were leaking hot-reheat bypass valves, hot drains flowing to the condenser, lack of knowledge about how all the systems affecting vacuum worked and interrelated, and the attitude of some operators regarding the importance of backpressure.

But the biggest challenge was finding and sealing all the places that air was leaking into the condenser. First step was to set a goal of 5 scfm of total air in-leakage. Once that was done, the Lindsay Hill O&M team studied how all the related systems were supposed to work and began corrective action. This included rental of a helium leak detector and training of the plant chemist in its use. Much of the overall effort focused on basics: instrument calibration and proper set-up and tuning of systems and equipment—such as the steam seal regulator and vacuum pumps.

Overcoming some shortcomings required design modifications. Addition of attemperator spray to hot drains entering the condenser at Central Alabama was one of these.

Central Alabama has achieved the 5-scfm goal. Plant output jumped by more than 7 MW as a result of the initiative; a large portion of the increase was attributed to the reduction in backpressure (more detail in "Plant capacity improvements," p 14). The Lindsay Hill team is still working toward the 5 scfm goal, but has already increased output by 3 MW because of lower backpressure. A 1% reduction in plant weighted average heat rate produced significant fuel saving (see "Improving condenser performance to increase plant output and efficiency," p 16).



9. Stress corrosion cracking occurs when a susceptible material is exposed to the optimum combination of stresses in the presence of a corrosive contaminant

Stress corrosion cracking in STs

EPRI's David Gandy picked up on Bignold's presentation the day before on steam-purity specifications and shared the industry's experience with a potentially dangerous failure mechanism that can occur when efforts to maintain steam purity fail. Stress corrosion cracking (SCC) occurs when a susceptible material is exposed to the optimum combination of stresses in the presence of a corrosive contaminant (Fig 9).

If stresses are high, even trace levels of the right contaminant can initiate cracking. Unfortunately, the rotor and blade materials required to operate successfully in the challenging LP-turbine environment are susceptible to SCC and high stress levels in these parts are the norm. This leaves the plant operator with the task of keeping contaminants out of the turbine if SCC is to be avoided.

The electric power industry became aware of just how dangerous SCC can be in 1969 when the UK's Hinkley Point Station experienced a major turbine wreck. In the years that followed, damage from SCC to more than 300 turbines worldwide was repaired. However, to date, SCC has not caused an ST failure in the combined-cycle fleet.

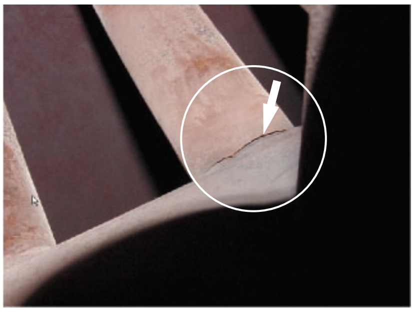
If steam-purity excursions are experienced at your plant, the turbine should be inspected for SCC. This can be very expensive, particularly if the examination requires the removal of LP turbine blades at the phase transition zone (where dry steam becomes wet) to look for cracks in the disc under the blade hook fits.

Gandy summarized his thoughts by saying that SCC can be found in discs, keyways, bores, blade attachments, and blades, and offered the following guidelines:

Disks and keyways. SCC is relatively rare today in these locations because (1) shrunk-on disks or keyways are not used on modern monoblock rotors, (2) materials chemistry has improved over the years, and (3) disks have lower yield strengths. The potential for SCC can be minimized by (1) avoiding condenser leakage, (2) eliminating ingress of contaminants, (3) maintaining excellent control of water treatment, (4) properly operating condensate polishers, and (5) by adhering to the latest shutdown and layup procedures.

Blade attachments. SCC is common here, but can be minimized by use of shot-peening, improved radii under hooks, and low-yield-strength disk materials. Reducing contaminant levels and following "to the letter" approved shutdown and layup procedures also have beneficial effect. If damage is located, Gandy said, excellent tools are available to predict remaining life.

Blades. SCC is rare and generally can be avoided by minimizing the entry of contaminants into the steam system. Cyclic stress should be prevented to the extent possible.



10. Severe fatigue damage caused by tube quenching eventually causes failure

Of drains and other challenges

Much has been said and written about the importance of effectively draining superheaters and reheaters during startup. Unfortunately, accomplishing this is easier said than done, began Chairman Anderson in his formal presentation. He explained that these heating surfaces behave like large air-cooled condensers during startup and generate large quantities of condensate on the steam side.

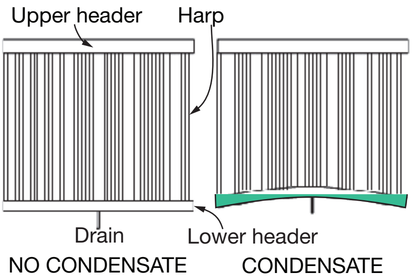
If this condensate is not drained prior to initiation of steam flow, it is carried with the steam and quenches some tubes and headers. Temperature differentials between adjacent tubes of up to several hundred degrees are common during such events. Severe fatigue damage caused by the quenching eventually leads to tube-to-header weld failure and cracking of header bores (Fig 10).

Anderson, who in the last few years has installed over 1200 tube temperature thermocouples in four HRSGs from different manufacturers, shared several data plots demonstrating that the severe tube temperature transients associated with condensate migration were common to all boilers studied.

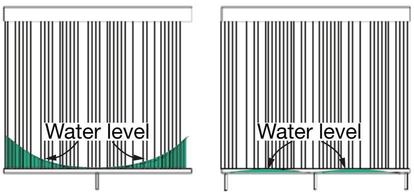
He illustrated the point that condensate migration events are very dynamic and cause many severe fatigue cycles during each startup by presenting a time-lapse animation of tube temperatures in a reheater coil throughout a startup. To receive a copy of this animation, write anderson@competitivepower.us. What follows is a summary of Anderson's recommendations for effectively draining condensate to avoid premature tube and header failure (refer to Figs 11-13).

Drain-system design objectives. An effective drain system must:
- Prevent high tube-to-tube temperature differentials.
- Prevent quenching of hot headers and pipes.
- Remove condensate at the rate of formation, under all startup conditions.
- Minimize loss of drum pressure during startup.
- Maintain tight shutoff of drain valves.
- Avoid overheating of blowdown system.

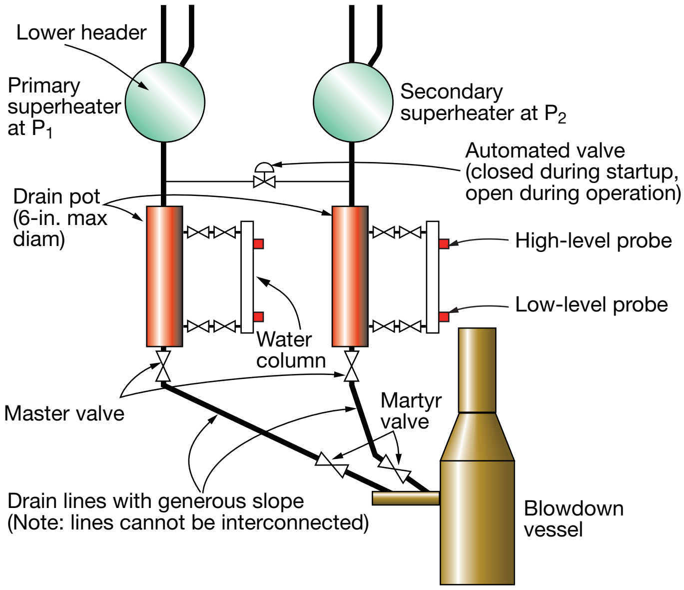
To achieve these objectives, the



11. Condensate falling into hot lower headers causes them to bow, trapping water near the ends if drains are not provided there



12. Condensate clears first from tubes closest to the drain. Damaging tube flooding can be prevented by providing properly located drains of adequate size



13. Properly designed drain system prevents unnecessary damage to tubes and headers drain system should be equipped to:

- Detect the presence of condensate.
- Automatically operate drain valves in a master/martyr sequence.
- Compensate for drum pressure.
- Accommodate two-phase flow.
- Leave no trapped condensate in headers, and interconnecting piping, or drain piping.
- Prevent transfer of condensate between coils at different pressures.

When planning a drain system for your plant, keep in mind that undrained condensate can flood HP superheater panels beyond half their height during a hot start. Further that effective drain sizing requires calculation of condensate formation rate in each superheater and reheater panel over a range of startup pressures. The near-zero-pressure case will set the minimum size of drain piping because of the low driving force available to move the condensate through the drain system.

Header drain location is especially important. Locate drain connections near the ends of headers, as shown in Fig 12. Other recommendations:

- Provide a generous slope for piping from drain pots to blowdown vessel.
- Use drain pots with maintainable level detection devices.
- Install separate blowdown vessels for superheaters and reheaters.
- Locate the martyr valve near the blowdown vessel. Note that fast-acting metal-seated ball valves are an option to modulated martyr valves.
- Control the martyr valve proportional to HP drum pressure.
- Automate drain controls to minimize the need for manual operation.

Finally, remember that drain-valve control is critical to effective condensate removal. A well-designed system:

- Must be operate automatically and be reliable.
- Have level probes that are maintainable with the HRSG pressurized.
- Employ fail-safe valve logic with alarms when faults occur.
- Be full open at low pressure, partially open at high pressure.

Reliable attemperation

The demanding conditions imposed on attemperation systems in fast-start, cycling service present challenges to valve designers and operators alike. No meeting on combined-cycle operation is complete without discussion of desuperheaters. Joe Steinke, a principal engineer at CCI Control Components Inc and certified Valve Doctor™, is an expert on severe-service valves. His presentation with Q&A extended for more than an hour because of the high level of interest.


Steinke

The work of CCI and Steinke recently were profiled in two COMBINED CYCLE Journal articles and they captured the essence of what the speaker had to say during the workshop. Readers are referred to "Attemperation frustrations—a clinic on severe-service valves," a section in the HRSG User's Group conference report, 2Q/2005, p 70, and "Tight specs, good engineering, quality manufacture ensure reliable control of steam temperature," 1Q/2005, p 24. Both can be accessed at www.psimedia.info/ccjarchives.htm.

Final presentation was by David Rasmussen of MD&A Consultants, "Maximizing benefits of next steam-turbine outage." Essentially it was a checklist of things to remember when planning for the outage. Points presented have been covered previously in the Outage Handbook supplements to the Summer 2004 and 3Q/2005 issues of the CCJ; both are available at the website address noted in the previous paragraph. CCJ